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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA.

Docket No. G-01551A-07-0504

NOTICE OF FILING SURREBUTTAL TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Surrebuttal Testimony of Marylee Diaz Cortez, CPA, William A. Rigsby, CRRA, and Rodney L. Moore in the above-referenced matter.

RESPECTFULLY SUBMITTED this 27th day of May 2008.

Daniel W. Pozefsky
Attorney

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SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

SURREBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 27, 2008

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INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. No. Mr. William Rigsby previously filed direct rate design testimony in this docket. I have adopted his direct testimony and will support both that testimony as well as the surrebuttal testimony I provide here.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony I will respond to the positions and arguments set forth by the various Arizona Water witnesses in their rebuttal testimony regarding rate design. I will show that certain arguments are without merit and demonstrate why such arguments should be rejected. I will reaffirm RUCO's positions on rate design.

Q. What rate design issues will you discuss in your surrebuttal testimony?

A. I will address the following rate design issues:

- Revenue Decoupling Adjustment Provision
- Weather Normalization Adjustment Provision
- Company Proposed "Allocated" Rate Design

REVENUE DECOUPLING ADJUSTMENT PROVISION (RDAP)

Q. Please discuss the Company's rebuttal comments concerning RUCO's recommendation to deny the proposed RDAP.

A. The Company rejects RUCO's recommendation to deny the RDAP and claims that RUCO's reasons for advocating rejection of the RDAP are not "a sound basis for rejecting it".

Q. What specifically does the Company consider "unsound" in RUCO's arguments?

A. The Company considers RUCO's regulatory lag, single-issue ratemaking, true-up, and conservation arguments to be "unsound".

Q. Do you agree with this characterization of RUCO's recommendation to deny the RDAP?

A. No. This characterization appears to merely reflect the Company's opinion, since SWG's rebuttal testimony presents no compelling evidence of the "unsoundness" of RUCO's position.

Q. Please discuss the Company's arguments concerning regulatory lag.

A. The Company first off agrees that declining average consumption is only problematic because of regulatory lag. However, the Company's agreement ends there. Rather than recognize that regulatory lag is a two way street from which the Company also benefits (i.e. accumulated depreciation, expired amortization, retirements, economies of scale, cost savings etc.) and that any attempt to mitigate the regulatory lag associated with declining average consumption and ignore the above mentioned regulatory lags that accrue to the shareholder the Company attempts to turn this into a conservation issue.

Q. Please explain.

A. The Company claims that the loss of revenue that results from declining average consumption coupled with regulatory lag creates an incentive for the utility to promote increased sales, which is counter productive to the conservation goals of the public and the Commission.

Q. Does this logic have merit?

A. No. First, there is absolutely no evidence to support this argument. In fact, all evidence contradicts this argument. By the Company's own acknowledgement, average consumption continues to decline, which clearly demonstrates that regulatory lag has had no effect on conservation. Second, in the same breath that the Company pleads economic harm from regulatory lag it also acknowledges that regulatory lag is "an incentive for the utility to prevent cost increases and even to achieve cost decreases, because the utility retains the financial benefit of any cost saving it achieves between rate cases, and it also retains the financial benefit of any cost increases it avoids."[1] This testimony supports RUCO's position that unfair and biased rates will result when extraordinary ratemaking schemes such as the RDAP are adopted.

Q. Please respond to the Company's rebuttal arguments regarding RUCO's objection to the RDAP being single-issue ratemaking?

A. The Company agrees in its rebuttal testimony that single issue ratemaking is biased yet then takes the stance that the "general objection to single issue ratemaking vanishes when a regulatory commission considers and then adopts an automatic adjustment clause in a general rate case, providing rate adjustments for changes in specific cost elements identified in advances of the changes in those elements. The RDAP fits this latter situation."[2]

Q. Is this true?

A. No. First, the proposed RDAP is not an automatic adjustment clause that provides for rate adjustments for changes in specific costs. In fact the RDAP, as proposed has nothing to do with specific cost increases or decreases. The RDAP would merely adjust the billing determinants used in assigning rates. Further, the RDAP would only adjust billing determinants for therms lost to conservation and ignore any gains in billing

[1] Rebuttal testimony of Ralph E. Miller, page 20, lines 5 through 8.
[2] Rebuttal testimony of Ralph E. Miller, page 19, lines 1 through 14.

determinants due to growth. In this respect it truly is biased and a perfect example of single issue ratemaking at its worst.

Q. Please discuss the Company's rebuttal comments concerning RUCO's position that the regulatory process already provides true-up of any changes in billing determinants are via rate cases.

A. The Company argues that RUCO is incorrect that billing determinants are trued-up during the rate case process.

Q. Why does the Company believe that RUCO is incorrect in this position?

A. The Company argues because there is no retroactive reimbursement for its perceived underrecoveries related to decreases in average consumption that there is no true-up.

Q. Do you agree?

A. No. Every time the Company files a rate case the bill determinants used in prior years to set rates are restated to the current bill determinants. Given the prohibition of retroactive ratemaking the Company is neither reimbursed for underrecoveries nor is it required to refund any overrecoveries. Nonetheless, the billing determinants used in the prior case to set rates are trued-up to the existing billing determinants, so that the new rates are based on the current level of billing determinants. RUCO made this point to simply demonstrate that the declines in average consumption over the last 20 years are not detrimentally affecting the Company since the declines are trued-up in each subsequent rate case.

Q. Please discuss the Company's rebuttal comments regarding the RDAP and conservation.

A. The Company argues that, contrary to RUCO's ascertain that the RDAP requires customers to pay for gas they didn't use and therefore is counterproductive to conservation, the RDAP does in fact deliver a conservation message because customers do avoid the pure gas commodity charge under the RDAP, albeit not the gas margin on therms not used.

Q. Please respond.

A. The Company is correct than conservation will save the customer the pure commodity charge for gas under the RDAP, however it still would require the customer to pay the margin on any therms not used (i.e. conserved). Thus, the price message as it relates to incenting conservation is diluted so that the customer will not see as compelling of a conservation price message under the proposed RDAP as they otherwise would absent the RDAP.

...

Q. Do any of the Company's rebuttal arguments regarding the proposed RDAP change RUCO's recommendations?

A. No. None of the Company's rebuttal arguments are compelling, let alone are even new arguments that have not already been presented in prior cases and forums. Further, to-date the AAC has rejected these arguments as well as all of the decoupling proposals that have been offered. RUCO believes the ACC has reached the appropriate conclusion in rejecting the previous decoupling proposals and recommends that it do so here again.

WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

Q. Please discuss the Company's rebuttal comments concerning RUCO recommendation to reject the proposed WDAP.

A. The Company does not agree with RUCO's recommendation to reject the WNAP, arguing that on a year-to-year basis fluctuations in weather have historically caused under and over recoveries of SWG's authorized revenue requirement. SWG believes that such fluctuations in weather warrant a WNAP that would guarantee the Company revenue requirement recovery regardless of weather.

...

Q. What rebuttal arguments does the Company present in its support for the proposed WNAP?

A. The Company makes three arguments in its rebuttal testimony. First, it argues that the WNAP does not require customers to pay for gas they do not use. Second, that the WNAP does not inappropriately shift risks from shareholders to ratepayers and third, that the primary cause for the Company's underrecoveries is not weather.

Q. Please address the first of these arguments.

A. The first argument that the WNAP dose not require customers to pay for gas they do not use is the same argument I addressed regarding the RDAP. To reiterate, when weather is warmer than normal the customer will save the pure commodity charge for gas under the WNAP, however the customer still would be required to pay the margin on any therms not used.

Q. Please address the second argument.

A. The Company argues that because the WNAP works in favor of the shareholder when weather is warmer than normal and it favors of ratepayers when weather is colder than normal it therefore does not shift the weather risk to ratepayers.

Q. Do you agree with this argument?

A. No. Both the RDAP and the WNAP would result in ratepayers bearing certain operational risks that currently are borne by shareholders. The cost of equity determined by the parties compensates for risk, and thus adoption of the WNAP or RDAP would warrant a reduction in the cost of equity to reflect the reduction in risk that these mechanisms would create.

Q. Has the Company proposed such an adjustment to the cost of equity?

A. No. The Company has proposed the same cost of equity with or without the RDAP and WNAP. In SWG's last case it proposed a lower cost of equity if a decoupling mechanism were adopted, in recognition of the decreased risk. The Company, in instant case fails to recognize or adjust for the decreased risks inherent in the RDAP and the WNAP.

Q. Please discuss the Company's third rebuttal argument.

A. The Company argues that over a ten year period, 1998 through 2007 the net effect of variations in weather was an increase in average use per customer as opposed to RUCO's position that the primary contributor of SWG's underrecoveries was weather related.

...

Q. How does this information serve to strengthen the Company case supporting the need for the WNAP?

A. It does not. As discussed in RUCO's direct testimony, the Company's rate case revenues are adjusted to annualize for a ten-year weather normalization. The Company now admits that this ten-year normalization has not only recovered the necessary weather related average use per customer, but has exceeded that amount. This information simply confirms that there is no justification for a WNAP since the ten-year weather normalization mechanism is already ensuring cost recovery due to variations in weather related consumption.

COMPANY PROPOSED ALLOCATED RATE DESIGN

Q. Please address the Company's proposed Allocated/Volumetric rate design[3].

A. The Company has proposed a somewhat unusual rate design, which SWG claims will alleviate some of its perceived declining consumption problems. SWG's proposed allocated rate design is characterized by a higher than normal non-gas commodity charge in the first tier and a $0.00 non-gas commodity charge in the second tier. The gas charge in the Company proposed allocated rate design is lower in the first tier than the actual estimated base cost of gas and higher in the second tier than the

[3] The Company proposed rate design is called an "allocated" rate design in its direct testimony and a "volumetric" rate design in its rebuttal testimony. Both terms refer to the same rate design. In my testimony I refer to the Company's proposed rate design using the "allocated" terminology.

actual estimated cost of gas. The Company proposed allocated rate design compares with a more traditional type rate design as follows:

	Traditional	"Allocated"
Fixed Monthly Charge	$12.80	$12.80
Non-gas Commodity		
All Usage	.55376	
First 35 Therms		.88069
Second 35 Therms		.00000
PGA Base		
All Therms	.93689	
First 35 Therms		.60996
Second 35 Therms		1.49065

The Company argues that the allocated rate design is fair to customers because the allocated rate design has a commodity cost of $1.49065 in both the first and second tiers (.60996 + .88069 = 1.49065) and so does the traditional rate design (.55376 + .93689 = 1.49065).

Q. Do you agree?

A. No. The impact of the allocated rate design is not revenue neutral to the customer when compared to a traditional rate design. The Company proposed allocated rate design has the effect of shifting a portion of the non-gas costs of large users to small users. I have prepared Surrebuttal Exhibit (A), which compares a residential customer's bill under a typical rate design to the Company-proposed allocated rate design. Under the allocated rate design small users (less than 55 therms consumption) will pay more than they would have under a traditional rate design. This is demonstrated on lines 1 – 10 of Surrebuttal Exhibit A. Users over 55 therms will pay less than they would have under a traditional rate design. Thus, the Company's proposed rate design shifts costs from large users to small users. This phenomena benefits the Company because it guarantees recovery of non-gas costs via the low usage blocks and SWG is thus financially indifferent to loss of consumption from high usage customers. The proposed allocated rate design results in small users paying more than they otherwise would of and large users paying less than they otherwise would have. This is certainly a perverse result that sends an undesirable message to ratepayers.

Q. Does RUCO's proposed rate design result in a fairer distribution of costs than the Company-proposed allocated rate design?

A. Yes. First, RUCO's proposed rate design does not shift costs from large users to small users, as does the Company's just described allocated rate design. Second, RUCO's proposed rate design charges the same price for each therm, which sends a better conservation message to consumers than SWG's current rate design which features a declining commodity price structure, where higher users pay less per therm than low users. Third, RUCO's proposed rate design assigns a slightly greater percentage of costs to the fixed charge than does SWG's current rate design. In this manner RUCO has addressed some of the Company's declining consumption and inability to recover cost concerns by essentially guaranteeing a greater fixed cost recovery. RUCO's rate design is fair to both the Company and ratepayer, as well as sends the correct conservation message.

Q. Doe this conclude your surrebuttal testimony?

A. Yes.

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
A TYPICAL RATE DESIGN VS. THE COMPANY-PROPOSED
"ALLOCATED" RATE DESIGN

SURREBUTTAL EXHIBIT A

LINE NO.	CONSUMPTION	AVERAGE (NORMAL) RATE DESIGN	COMPANY PROPOSED "ALLOCATED" RATE DESIGN
	20 THERMS		
1	MONTHLY MINIMUM	$12.80	12.80
2	BASE COMMODITY	11.08	17.61
3	PGA	18.74	12.20
4	PGA ADJUSTOR	0.00	6.54
5	TOTAL	42.61	49.15
	40 THERMS		
6	MONTHLY MINIMUM	$12.80	12.80
7	BASE COMMODITY	22.15	30.82
8	PGA	37.48	28.80
9	PGA ADJUSTOR	0.00	8.67
10	TOTAL	72.43	81.10
	55 THERMS		
11	MONTHLY MINIMUM	$12.80	12.80
12	BASE COMMODITY	30.46	30.82
13	PGA	51.53	51.16
14	PGA ADJUSTOR	0.00	0.37
15	TOTAL	94.79	95.15
	60 THERMS		
16	MONTHLY MINIMUM	$12.80	12.80
17	BASE COMMODITY	33.23	30.82
18	PGA	56.21	58.61
19	PGA ADJUSTOR	0.00	(2.40)
20	TOTAL	102.24	99.84
	80 THERMS		
21	MONTHLY MINIMUM	$12.80	12.80
22	BASE COMMODITY	44.30	30.82
23	PGA	74.95	88.43
24	PGA ADJUSTOR	0.00	(13.48)
25	TOTAL	132.05	118.58
	100 THERMS		
26	MONTHLY MINIMUM	$12.80	12.80
27	BASE COMMODITY	55.38	30.82
28	PGA	93.69	118.24
29	PGA ADJUSTOR	0.00	(24.55)
30	TOTAL	161.87	137.31
	120 THERMS		
31	MONTHLY MINIMUM	$12.80	12.80
32	BASE COMMODITY	66.45	30.82
33	PGA	112.43	148.05
34	PGA ADJUSTOR	0.00	(35.63)
35	TOTAL	191.68	156.05
	140 THERMS		
36	MONTHLY MINIMUM	$12.80	12.80
37	BASE COMMODITY	77.53	30.82
38	PGA	131.16	177.87
39	PGA ADJUSTOR	0.00	(46.70)
40	TOTAL	221.49	174.79

	AVERAGE RATES	"ALLOCATED" RATES
BASIC SERVICE CHRG.	12.8	12.80
BASE COMMODITY		
ALL USAGE	0.55376	
FIRST 35 THERMS		0.88069
SECOND 35 THERMS		0.00000
PGA		
ALL THERMS	0.93689	
FIRST 35 THERMS		0.60996
SECOND 35 THERMS		1.49065

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 27, 2008

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INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on March 28, 2008, I filed direct testimony with the ACC. My direct testimony addressed the cost of capital issues that were raised in SWG's application requesting a permanent rate increase based on a test year ended April 30, 2007, and presented RUCO's recommended hypothetical capital structure in addition to RUCO's recommended returns on debt and equity. On April 11, 2008, I also filed direct testimony on RUCO's policy considerations that shaped RUCO's recommended rate design.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to respond to SWG's rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt, cost of preferred equity and cost of common equity) for the Company's natural gas distribution operations in Arizona.

...

Q. Will you also be filing surrebuttal testimony on rate design issues?

A. No. RUCO's Chief of Accounting and Rates, Marylee Diaz Cortez, CPA will adopt my prior direct testimony and provide surrebuttal testimony on the policy considerations associated with RUCO's recommended rate design.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of SWG's rebuttal testimony; a section on the capital structure and cost of debt issues associated with the case; and a section on the cost of equity capital issues associated with the case.

SUMMARY OF SOUTHWEST GAS' REBUTTAL TESTIMONY

Q. Have you reviewed the rebuttal testimony of Company witnesses Theodore K. Wood and Frank J. Hanley?

A. Yes. I have reviewed the rebuttal testimony, on cost of capital issues, filed by the aforementioned Company witnesses on May 9, 2008.

Q. Please summarize the testimony filed by Company witness Wood.

A. Mr. Wood's rebuttal testimony concentrates on the capital structures recommended by the Company, ACC Staff cost of capital consultant David C. Parcell, and RUCO. Mr. Wood also compares and comments on the overall rate of return recommendations being made by the Company, ACC Staff and RUCO. Mr. Wood takes issue with the cost of common equity being recommended by Mr. Parcell and myself stating that our respective recommended costs of common equity of 10.00 percent and 9.88 percent are too low. He also comments on the overall weighed costs of capital that Mr. Parcell and myself have recommended.

Q. Please summarize the testimony filed by Company witness Hanley.

A. Mr. Hanley's rebuttal testimony focuses entirely on the cost of common equity recommendations of ACC Staff and RUCO. Mr. Hanley is critical of my reliance on the discounted cash flow ("DCF") model and the manner in which I arrived at my DCF growth estimates. This includes my reliance on the assumption that a utility's market to book ratio will move in the direction of 1.0 if regulators set a utility's rate of return at a level that is equal to the utility's cost of capital and my reliance on the sustainable growth concept that is expressed in the growth component of the DCF model. Mr. Hanley also takes issue with the inputs used in my capital asset pricing model ("CAPM") analyses and the use of a geometric mean in the calculation of the return on the market. Mr. Hanley further takes issues with the opinions I expressed on the ECAPM model which he relied upon in his cost of capital analysis. Mr. Hanley is also critical of the position that RUCO has taken in regard to the Company-proposed decoupling mechanisms (i.e. the RDAP, WNAP).

CAPITAL STRUCTURE AND WEIGHTED COST OF CAPITAL

Q. Have you made any changes to your recommended hypothetical capital structure, cost of debt, cost of preferred equity or cost of common equity?

A. No. I have not made any changes to the recommendations presented in my direct testimony.

Q. Briefly summarize the positions of the parties in the case in regard to capital structure, cost of debt, cost of preferred equity and cost of common equity.

A. Both RUCO and the Company are recommending identical hypothetical capital structures comprised of 51 percent long-term debt, 4 percent preferred equity and 45 percent common equity. RUCO and the Company are also in agreement on the Company-proposed 7.96 percent cost of debt and 8.20 percent cost of preferred equity.

ACC Staff consultant Parcell is recommending that the Commission adopt SWG's actual capital structure at the end of the test year which is comprised of 52.7 percent long-term debt, 4.4 percent preferred equity, and 42.9 percent common equity. Mr. Parcell is also in agreement with both RUCO and SWG in regard to his recommended costs of long-term debt and preferred equity.

The costs of common equity presently being recommended by the parties to the case are as follows:

SWG	11.25%
ACC Staff	10.00%
RUCO	9.88%

The weighted costs of capital presently recommended by the parties to the case are as follows:

SWG	9.45%
ACC Staff	8.86%
RUCO	8.83%

As can be seen above, there is presently a 62 basis point difference between the Company-proposed 9.45 percent weighted cost of capital and my recommended weighted cost of capital of 8.83 percent. RUCO and ACC Staff's recommended weighted costs of capital fall within 3 basis points of each other.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On April 30, 2008, the Fed cut interest rates for a seventh straight time. The reduction was a much smaller 25 basis point move as opposed to the 50 and 75 basis point cuts made earlier this year. As a result of the

Feds recent action, the federal funds rate now stands at 2.0 percent[1]. A list of the most recent yields of various financial instruments can be seen in Attachment A to my testimony.

Q. Please respond to Mr. Wood and Mr. Hanley's rebuttal positions that your recommended cost of equity is too low.

A. Given the fact that Mr. Parcell's and my cost of common equity estimates fall within 12 basis points of each other, I would have to say that just the opposite is true. As I stated in my direct testimony, Mr. Hanley's 11.25 percent recommendation (which I commented on in pages 52 through 59 of my direct testimony) ignored any results he obtained that were lower than 9.60 percent and therefore produced a higher estimate.

Q. Do you agree with Mr. Wood's position that your final recommended cost of equity for SWG should have been a midpoint figure that falls within your estimated range of 9.20 percent to 10.83 percent?

A. No, I do not. My final 9.88 percent recommended cost of equity for SWG was arrived at using the same calculation (i.e. a mean average of DCF and CAPM results) that ACC Staff has used in a number of rate case proceedings before the Commission. The Commission has consistently adopted ACC Staff's recommendations that were calculated in this manner. In addition, my recommended 9.88 percent cost of equity for

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[1] Ip, Greg, "Fed Cuts Key Rate, Signals a Pause," The Wall Street Journal Online Edition, May 1, 2008.

SWG is 15 basis points higher than the 9.73 percent result derived from my DCF model (that relies on utility-specific data inputs), which I believe to be superior to the CAPM.

Q. Please address Mr. Wood's argument that you should have made an upward adjustment to your 9.88 percent cost of equity estimate based on SWG's credit rating in relation to the credit rating of your sample LDC's.

A. Mr. Wood disagrees with my position that the adoption of the Company-proposed capital structure provides SWG with adequate compensation for additional financial risk. Mr. Wood further believes that it is not enough to provide the Company with a level of equity that does not exist – a level of equity that also provides the Company with additional cash flow by way of a synchronized interest calculation (which produces a level of income tax expense that is higher than what the Company's actual level of deductible interest expense would produce) – and argues that an additional upward adjustment needs to be made.

Q. Does Mr. Wood's argument have any merit?

A. No. In addition to the additional cash flow that I noted above, the Company will realize additional operating income that it would not have realized under its actual capital structure. This does not include RUCO's recommended rate design changes, or other factors which I will discuss later, that also favor the Company. An upward adjustment to my recommended cost of equity might well reduce the incentive for SWG to actually achieve a level of equity that would help raise the Company's current credit rating. Furthermore, the outlook for SWG is actually quite favorable despite the picture painted by Mr. Wood. This is evidenced from an April 24, 2008 Standard & Poor's credit rating report provided by the Company in its supplemental response to ACC Staff data request STF-2-7 (Attachment B).

On the subject of SWG's liquidity situation, the report states the following:

> Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses for liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.
>
> Given the low-risk nature of Southwest Gas' regulated utility operations and healthy service territory, the company should generate reasonably stable cash flow. The company reported cash from operations of almost $350 million for 2007, which will not fully cover annual dividends (about $36 million), annual capital expenditures (about $300 million forecast for 2008 and about $550 forecast for 2009-2010 combined), and near-term debt maturities ($38 million due in 2008 and $10 million in 2009). To bridge the funding gap, the company expects to raise $70 million to $80 million through stock offerings, borrow under its revolving credit facility, or through other external means.

The report goes on to present the following outlook (the second sentence of which Mr. Wood included in his testimony) for SWG:

> The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Rating Services' expectation that the company's improved financial performance could lead to a higher rating over the near-term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

Based on the information above, I believe that RUCO's recommendations, that provide additional and more stable revenue, will only further strengthen SWG's existing liquidity position.

Q. Do you agree with Mr. Wood's use of the Hamada adjustment to justify SWG's 25 basis point upward adjustment for financial risk, and to justify his arguement that RUCO's recommended 9.88 percent cost of equity is too low?

A. No. Although Mr. Wood employed the Hamada methodology presented by RUCO consultant Stephen G. Hill in his direct testimony in the Arizona Public Service Company ("APS") rate case proceeding[2] to arrive at changes in CAPM estimates (ranging from 63 to 107 basis points using a relevered beta of 0.97), he ignores the argument for lower market risk premiums of 4.0 percent to 6.0 percent that Mr. Hill presents in the "Hamada portion" of his APS testimony[3] (Attachment C). On page 46 of his APS testimony, Mr. Hill supports his argument for lower market risk premiums by citing two scholarly articles on the subject published over the past six years by noted academics. In the first paper titled *The Equity Premium*, published in 2002, Eugene Fama and Kenneth French take the position that Ibbotson Associates' historical market risk premiums (now published by Morningstar) have overstated investor expectations. Mr. Hill

[2] Docket No. E-01345A-05-0816 et al.

[3] Lines 25 through 29 of page 45, and lines 1 through 4 of page 46 of the direct testimony of RUCO consultant Stephen G. Hill, Docket No. E-01345A-05-0816 et al.

also cites a paper authored by Carl Ibbotson himself which indicates that investors can expect future returns of 4.0 to 6.0 percent.

Q. Can you cite any other sources that support Mr. Hill's views, in his APS rate case testimony, that 4.0 percent to 6.0 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University in Washington D.C. on April 19 and 20, 2007, both Mr. Wood and myself had the opportunity to hear the views of Aswarth Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston advocated 4.0 to 5.5 percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

...

Q. What would your CAPM results be if the market risk premiums of 4.0 percent to 6.0 percent, advocated by Mr. Hill, were used in your CAPM model with the 0.97 relevered beta calculated by Mr. Wood?

A. Using the 91-day T-bill rate of 1.65 percent (r_f) that I used in my analysis, Mr. Wood's relevered beta of 0.97, and the market risk premiums (r_m - r_f) of 4.0 percent to 6.0 percent, advocated by Mr. Hill, in my CAPM model produces expected returns of 5.53 percent and 6.85 percent respectively. These results are much lower than the 9.20 percent and 10.93 percent estimates that I used to calculate my recommended 9.88 percent cost of equity.

For the sake of the arguments presented by Mr. Hanley on pages 27 through 29 of his rebuttal testimony, if the most recent 4.61 percent yield on a 30-year U.S. Treasury note (the same long-term Treasury instrument preferred by Mr. Hanley) were used in the CAPM model, the results would be as follows:

<u>Using a 4.0% Market Risk Premium</u>

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

$$k = 4.61\% + [\, 0.97\,(4.0\%)\,]$$

$$k = \underline{8.49\%}$$

...

Using a 6.0% Market Risk Premium

$$k = r_f + [\ ß\ (r_m - r_f)\ ]$$

$$k = 4.61\% + [\ 0.97\ (6.0\%)\ ]$$

$$k = \underline{10.43\%}$$

As can be seen above, the range of CAPM estimates using a higher and more recent risk free yield (using Mr. Hanley's preferred financial instrument), the larger relevered beta coefficient (calculated by Mr. Wood using the Hamada methodology) and the 4.0 percent to 6.0 percent market risk premiums (advocated by Mr. Hill in his APS testimony), produces a lower estimate range of 8.49 percent to 10.43 percent (or an average of 9.46 percent) versus my higher original CAPM estimate range of 9.20 percent to 10.83 percent (or an average of 10.02 percent) presented in my direct testimony. Collectively this data demonstrates that my unadjusted recommended 9.88 percent cost of common equity appears to be reasonable compared to the Hamada methodology results advocated by Mr. Wood and the lower market risk premiums advocated by Mr. Hill.

Q. Please comment on the discussion of the DCF growth component that Mr. Hanley offers on pages 24 and 25 of his rebuttal testimony.

A. Mr. Hanley cites a 1990 presentation by Dr. Myron Gordon who refers to the findings he presented on analysts estimates of growth ("g") in a 1989 paper he coauthored titled *Choice among methods of estimating share yield*[4]. Mr. Hanley also cites the opinions of Dr. Roger Morin on the problems of estimating the DCF growth component which appear on pages 306 and 307 of Dr. Morin's 2006 text New Regulatory Finance.

Q. Do you believe that your 5.18 percent DCF growth estimate is unreasonable based on the information provided in the above-referenced documents?

A. No. As a matter of fact, on page 308 of his text, Dr. Morin provides a DCF growth rate check (Attachment D). The reasonableness test offered by Dr. Morin is expressed as follows:

Dividend Growth = Risk Free Return + Risk Premium – Dividend Yield

Under the above formula the dividend yield element of the DCF ("D_1/P_0") is subtracted from results of a CAPM calculation ("$r_f + [\, ß\, (r_m - r_f)\,]$").

Q. How does your 5.18 percent growth estimate compare to the results obtained from the reasonableness test offered by Dr. Morin?

A Using the CAPM results presented above using Mr. Wood's relevered beta of 0.97, the most recent yield of a 30-year U.S. Treasury note (Mr.

[4] Gordon, David with Myron J. Gordon and Lawrence I. Gould, "Choice among methods of estimating share yield," The Journal of Portfolio Management, pp. 50-55, Spring 1989.

Hanley's preferred instrument), the 4.0 percent to 6.0 percent market risk premium (advocated by Mr. Hill in his APS testimony) and the average 4.55 percent dividend yield estimate presented in my direct testimony, the following growth rate check results are obtained:

<u>Using a 4.0% Market Risk Premium</u>

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.61\% + [\,0.97\,(4.0\%)\,] - 4.55\%$$

$$g = 4.61\% + 3.88\% - 4.55\%$$

$$g = \underline{3.94\%}$$

<u>Using a 6.0% Market Risk Premium</u>

$$g = r_f + [\,ß\,(r_m - r_f)\,] - (D_1/P_0)$$

$$g = 4.61\% + [\,0.97\,(6.0\%)\,] - 4.55\%$$

$$g = 4.61\% + 5.82\% - 4.55\%$$

$$g = \underline{5.88\%}$$

As can be seen above, the growth rate check results, obtained from Dr. Morin's reasonableness test, range from 3.94 percent to 5.88 percent or an average of 4.91 percent which is 27 basis points lower than my 5.18 percent DCF growth rate estimate.

...

Q. In the examples that you've provided above you have used Mr. Hanley's preferred 30-year U.S. Treasury note as a proxy for the risk-free rate of return. Is it reasonable to assume that a 30-year horizon is appropriate for ratemaking purposes?

A. Not really. An argument can be made that the financial instrument used for a risk free rate of return should have a maturity that is close to the time frame that a utility typically files for new rates. If one assumes that a utility typically applies for new rates every three to five years, then a better instrument would probably be a 5-year U.S. Treasury note. As can be seen in Attachment A, the current yield on a 5-year U.S. Treasury note is 3.20 percent or 141 basis points lower than the 30-year 4.61 yield that I have used in the examples above.

Q. What would the average CAPM expected rate of return be if you substituted the current 4.61 percent yield on a 30-year U.S. Treasury note with the current 3.20 percent yield for a 5-year U.S. Treasury note and held all of the other components used in the above examples constant?

A. Substituting the 5-year U.S. Treasury note yield of 3.20 percent and holding all of the other inputs constant produces an average CAPM expected rate of return of 8.05 percent which is probably more reasonable given the fact that utility rates are typically not set for 30-year periods.

Using Dr. Morin's reasonableness test produces an average growth rate check result of 3.50 percent which is 168 basis points lower than my 5.18 percent DCF growth estimate.

Q. On page 26 of his rebuttal testimony, Mr. Hanley criticizes your DCF analysis, which takes into consideration the concept that a utility's market-to-book ratio will move toward a value of 1.0 if regulators set a utility's rate of return at a level that is equal to its cost of capital. Please explain why you believe that the market value of a utility's stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital of firms with similar risk.

A. A utility's market price should equal its book price over the long run if regulators allow a rate of return that is equal to the utility's cost of capital. *That is assuming that the utility's rate of return ("ROR") is comparable to the rates of return of other firms in the same risk class.*[5] For example, if a hypothetical utility's book price is $20.00 per share and regulators adopt a rate of return that is equal to the utility's cost of capital of 10.0%, the utility will earn $2.00 per share ("EPS"). With earnings of $2.00 per share, and a market required rate of return on equity of 10.00%, for firms in the utility's risk class, the market price of the utility's stock will set at $20.00 per share ($2.00 EPS ÷ 10.0% ROR = $20.00 per share price). If the utility records earnings that are higher than the earnings of other firms with similar risk,

[5] An in-depth discussion of market-to-book ratios can be found in Chapter 10 of Roger A. Morin's text Regulatory Finance, Utilities' Cost of Capital.

the market value of the utility's shares will increase accordingly ($2.50 EPS ÷ 10.0% ROR = $25.00 per share). On the other hand, if the utility posts lower earnings, the stock's market price will fall below book value ($1.50 EPS ÷ 10.0% ROR = $15.00 per share).

Because of economic forces beyond the control of regulators, it is not reasonable to assume that the utility will have earnings that match those of firms of similar risk in every year of operation. In some years, earnings may drop causing the market-to-book ratio to fall below 1.0, while in other years the utility may have earnings that exceed those of other firms in its risk classification. However, over the long run the utility's earnings should average out to the earnings that are expected based on its level of risk. These average earnings over time will result in a market-to-book ratio of 1.0. It has been suggested that regulators should set a utility's rate of return at a level that is slightly higher than that of firms in the same risk class of the hypothetical utility. In theory, this will send a message to investors that average long-term earnings will not be less than what is expected. A 1.0 ratio may never be achieved in practice and many investors may not even care what the market-to-book ratio is as long as they receive their required rate of return. In this respect, a utility stock is similar to a corporate bond whose value fluctuates as interest rates move above or below the stated yield on the bond. As long as the bond provides the level of income (i.e. the stated interest payment in the case of a bond or a dividend payment in the case of a utility stock) that the investor expects, the price of the instrument at any given point in time is immaterial (so long as the intent is to hold the bond until maturity or the utility stock over a long-term period).

Q. Does your recommended cost of equity take into consideration the theoretical concepts that you have just described?

A. Yes. As I just explained, in theory, a market-to-book ratio of 1.0 would be achieved if a utility's rate of return equaled the cost of capital that is close to the returns of firms with similar risk. The CAPM analysis that I performed earlier in this testimony (using the current yield on a 5-year U.S treasury note and the revised beta and market risk premium inputs advocated by Mr. Wood and Mr. Hill) indicates that the rate of return for a firm with SWG's level of risk is 8.05 percent. This being the case, the adoption of my recommended 8.83 percent cost of capital would be consistent with the theory I have presented above since it is 78 basis points higher than the aforementioned average 8.05 percent expected rate of return that theoretically produces a market price that is equal to book value.

Q. Please explain why Mr. Hanley's criticism regarding the use of a geometric mean in your CAPM analysis is unfounded.

A. While it is true that an ongoing debate exists as to which mean is the better one to use, it is important to recognize that the information on both means, published by Morningstar, is widely available to the investment community. For this reason, and the fact that the ACC has consistently accepted the use of both means, I believe that the use of both means in a CAPM analysis is appropriate.

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2006 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the differences between the two averages?

A. Yes. The following example may help. Suppose you invest $100 and realize a 20.0 percent return over the course of a year. So at the end of year 1, your original $100 investment is now worth $120. Now let's say that over the course of a second year you are not as fortunate and the value of your investment falls by 20.0 percent. As a result of this, the $120 value of your original $100 investment falls to $96. An arithmetic mean of the return on your investment over the two-year period is zero percent calculated as follows:

$$(\text{year 1 return} + \text{year 2 return}) \div \text{number of periods} =$$

$$(20.0\% + -20.0\%) \div 2 =$$

$$(0.0\%) \div 2 = \underline{\underline{0.0\%}}$$

The arithmetic mean calculated above would lead you to believe that you didn't gain or lose anything over the two-year investment period and that your original \$100 investment is still worth \$100. But in reality, your original \$100 investment is only worth \$96. A geometric mean on the other hand calculates a compound return of negative 2.02 percent as follows:

$$(\text{year 2 value} \div \text{original value})^{1/\text{number of periods}} - 1 =$$

$$(\$96 \div \$100)^{1/2} - 1 =$$

$$(0.96)^{1/2} - 1 =$$

$$(0.9798) - 1 =$$

$$-0.0202 = \underline{\underline{-2.02\%}}$$

The geometric mean calculation illustrated above provides a truer picture of what happened to your original \$100 over the two-year investment period.

As can be seen in the preceding example, in a situation where return variability exists, a geometric mean will always be lower than an arithmetic mean, which probably explains why utility consultants typically put up a strenuous argument against the use of a geometric mean.

Q. Can you cite any other evidence that supports your use of both a geometric and an arithmetic mean?

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been regarded as being more forward-looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's Stocks Bonds Bills and Inflation 2007 Yearbook ("Morningstar").

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However, research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms. That is, those firms that are listed on stock exchanges. The Morningstar historical return series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM concludes that 4.0 percent to 5.5 percent is a reasonable forward-looking market risk premium (a point raised earlier in my testimony). Adding the current 5-year Treasury yield of 3.20 percent to these two estimates indicate a cost of equity of 7.20 percent to 8.70 percent or an average of 7.95 percent which is 88 basis points lower than my recommended 8.83 percent cost of capital for SWG.

Q. Has any of Mr. Hanley's testimony on the ECAPM persuaded you to make any adjustments to your recommended cost of common equity?

A. No. On this issue I disagree with both Mr. Hanley and Dr. Morin. The flatter security market line produced by the CAPM (which is referred to by Dr. Morin in Mr. Hanley's cite), is the result of a phenomenon known as regression toward the mean. The ECAPM using raw, or unadjusted betas, takes this phenomenon into account. This same phenomenon also occurs in the calculation of betas and results in the long term tendency of betas to move toward a value of 1.00. As I explained my direct testimony, this is the reason why Value Line betas are adjusted. Since the ECAPM model already takes regression toward the mean into account, there is no need to use adjusted Value Line betas in the ECAPM. In short, the use of adjusted betas in the ECAPM will result in a double count. For this reason the appropriate beta to use in the ECAPM is a raw or unadjusted beta. As I further stated in my direct testimony, the Commission has consistently rejected the results of the ECAPM in a number of water company cases that have come before the ACC. For these reasons, Mr. Hanley's ECAPM results using adjusted betas should be given no weight.

Q. Are you recommending a lower cost of capital for SWG based on the lower CAPM estimates that you have just presented in your testimony?

A. No.

Q. Please address Mr. Hanley's argument that the adoption of a decoupling mechanism for SWG would not warrant a lower rate of return for the Company?

A. I agree with Mr. Hanley that this is simply a matter of common sense. However, I believe that common sense says that if SWG's revenues are stabilized, the risks are clearly shifted to the ratepayers as opposed to the Company – which has the ability to control the majority of its operating expenses and pass through its cost of natural gas to customers.

Q. Are there any states that you are aware of that have made downward adjustments to an LDC's authorized rate of return due to the implementation of a revenue decoupling mechanism?

A. Yes. On pages 11 and 12 of his April 2006 briefing paper titled <u>Revenue Decoupling for Natural Gas Utilities</u> (Attachment E), Ken Costello, a Senior Institute Economist with the National Regulatory Research Institute, cites the Maryland Public Service Commission's decision to reduce the authorized rate of return for Baltimore Gas and Electric by 50 basis points to reflect the reduced revenue risk associated with that utility's decoupling mechanism. Such an adjustment would lower my recommended cost of capital from 8.83 percent to 8.33 percent.

Q. Does your silence on any of the positions advocated by Mr. Wood or Mr. Hanley constitute your acceptance of them?

A. No, it does not.

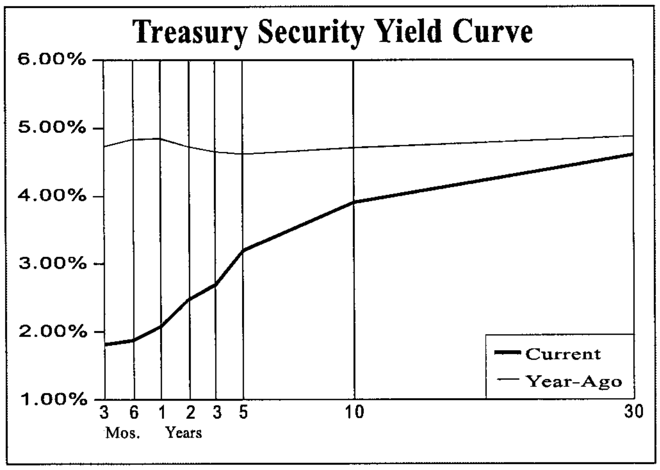
Q. Does this conclude your surrebuttal testimony on SWG?

A. Yes, it does.

ATTACHMENT A

Selected Yields

	Recent (5/14/08)	3 Months Ago (2/13/08)	Year Ago (5/16/07)
TAXABLE			
Market Rates			
Discount Rate	2.25	3.50	6.25
Federal Funds	2.00	3.00	5.25
Prime Rate	5.00	6.00	8.25
30-day CP (A1/P1)	2.70	3.00	5.24
3-month LIBOR	2.72	3.07	5.36
Bank CDs			
6-month	1.77	2.15	3.11
1-year	2.05	2.34	3.73
5-year	3.16	2.85	3.91
U.S. Treasury Securities			
3-month	1.82	2.26	4.73
6-month	1.88	2.09	4.84
1-year	2.08	2.06	4.85
5-year	3.20	2.73	4.62
10-year	3.91	3.73	4.71
10-year (inflation-protected)	1.35	1.34	2.37
30-year	4.61	4.54	4.88
30-year Zero	4.71	4.65	4.85



	Recent (5/14/08)	3 Months Ago (2/13/08)	Year Ago (5/16/07)
Mortgage-Backed Securities			
GNMA 6.5%	5.04	4.46	5.58
FHLMC 6.5% (Gold)	5.16	5.10	5.80
FNMA 6.5%	4.90	4.71	5.73
FNMA ARM	4.41	5.18	5.49
Corporate Bonds			
Financial (10-year) A	5.68	5.78	5.69
Industrial (25/30-year) A	6.06	6.29	5.89
Utility (25/30-year) A	6.10	6.20	6.07
Utility (25/30-year) Baa/BBB	6.41	6.35	6.21
Foreign Bonds (10-Year)			
Canada	3.60	3.87	4.24
Germany	4.17	3.96	4.30
Japan	1.68	1.43	1.67
United Kingdom	4.82	4.62	5.13
Preferred Stocks			
Utility A	6.28	6.13	6.07
Financial A	7.69	7.00	6.48
Financial Adjustable A	5.51	5.51	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.62	4.33	4.24
25-Bond Index (Revs)	5.07	4.72	4.44
General Obligation Bonds (GOs)			
1-year Aaa	1.83	1.05	3.60
1-year A	1.93	1.15	3.70
5-year Aaa	2.97	2.67	3.63
5-year A	3.07	2.77	3.74
10-year Aaa	3.62	3.40	3.76
10-year A	3.83	3.60	4.26
25/30-year Aaa	4.55	4.36	4.13
25/30-year A	4.75	4.56	4.43
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.80	4.60	4.55
Electric AA	4.85	4.65	4.45
Housing AA	5.00	4.80	4.63
Hospital AA	5.05	4.85	4.65
Toll Road Aaa	4.85	4.65	4.55

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/7/08	**4/23/08**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1980	1718	262	2201	1953	2042
Borrowed Reserves	129197	133027	-3830	89011	52907	27699
Net Free/Borrowed Reserves	-127217	-131309	4092	-86810	-50954	-25657

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	4/28/08	**4/21/08**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1379.9	1372.1	7.8	4.6%	1.4%	-0.2%
M2 (M1+savings+small time deposits)	7654.1	7693.3	-39.2	7.6%	7.1%	6.1%

ATTACHMENT B

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 THROUGH ACC-STF-2-22)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 19, 2007

Request No. STF-2-7:

Please provide copy of all reports on Southwest Gas by rating agencies for the period 2003 to the present.

Respondent: Treasury Services

Response: ***Supplemental Attachment Provided on May 9, 2008***

Supplemental Attachment Provided on March 6, 2008

Supplemental Attachment Provided on January 7, 2008

Southwest's credit rating agency reports for 2004-2007 were provided in response ACC Staff data request no. STF-1-10. Attached are the credit rating agency reports for 2003.

Update
Data Request No. STF-2-7

Summary:
Southwest Gas Corp.

Credit Rating: BBB-/Positive/--

Rationale

The ratings on Las Vegas, Nev.-based Southwest Gas Corp. reflect its strong business risk profile and aggressive financial risk profile. The ratings are based on the consolidated credit profile of its natural gas operations segment (87% of operating income in 2007) and its construction services business, Northern Pipeline Construction Co. (NPL; 13%).

Southwest Gas' strong business risk profile reflects a large, stable, residential, and commercial customer base of about 1.8 million customers, strong customer growth prospects in Arizona (54% of customers), Nevada (36%), and California (10%), the absence of competition, and relatively low operating risks. Challenges associated with improving its regulatory cost-recovery mechanisms, ownership of a small, unregulated construction and maintenance business, gradual reductions in total gas volumes, and limited geographic service territory temper the company's strong business profile.

The Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada, and the California Public Utilities Commission each regulate Southwest Gas. Each regulatory commission provides the company with various cost-recovery mechanisms. However, we view the ACC regulatory oversight as less supportive of credit than other jurisdictions due to its limitations on purchased-gas cost recoveries and rate design that is solely based on gas throughput. This type of rate design exposes the company to reduced cash flows as volumes decline related to conservation. Decoupling, an alternate rate design, separates the utility's margins and cash flow from commodity sales and encourages conservation. These mechanisms are currently under consideration as part of the company's most recent rate case.

Slowing customer growth, reduced total throughput, and improved rate design are among the reasons for Southwest Gas' recent rate filings. While Southwest Gas' annual customer growth averaged more than 4% over the past five years, the company expects future growth to be only 1.5% to 3% due to the depressed real estate market conditions. Despite strong historical customer growth statistics, annual total consumption has nevertheless dropped 1% per year, on average, since 2003, due to conservation efforts, making rate design a key credit driver for the company.

Southwest Gas' nonregulated subsidiary, NPL, is not currently a significant rating factor because most of its contracts shield Southwest Gas from the majority of costs. In addition, about 20% of NPL's revenues are derived from Southwest Gas' gas operations.

Southwest Gas has an aggressive financial risk profile, with bondholder protection measures that are currently strong for the rating, which supports the positive outlook. We expect near-term performance to remain strong for the rating with additional improvements from customer growth and regulatory rate increases. As of Dec. 31, 2007, total debt, including operating leases and tax-affected pensions and post-retirement obligations, was about $1.5 billion with debt to capital of almost 60%. Benefitting from customer growth and regulatory rate increases, cash flow metrics have improved over the past few years, with 2007 adjusted funds from operations (FFO) to total debt of 20% and FFO interest coverage of about 4x, compared with 14% and 3.4x, respectively, in 2005.

Liquidity

Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses of liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.

Given the low-risk nature of Southwest Gas' regulated utility operations and healthy service territory, the company should generate reasonably stable cash flow. The company reported cash from operations of almost $350 million for 2007, which will not fully cover annual dividends (about $36 million), annual capital expenditures (about $300 million forecast for 2008 and about $550 forecast for 2009-2010 combined), and near-term debt maturities ($38 million due in 2008 and $10 million in 2009). To bridge the funding gap, the company expects to raise $70 million to $80 million through stock offerings, borrow under its revolving credit facility, or through other external means.

Outlook

The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Ratings Services' expectation that the company's improved financial performance could lead to a higher rating over the near term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

Southwest Gas Corp.

Major Rating Factors

Corporate Credit Rating

BBB-/Positive/--

Strengths:

- A low-risk natural gas distribution business;
- A favorable customer mix and high growth service territories;
- Purchased-gas adjustment (PGA) mechanisms that eliminate a majority of the company's exposure to commodity prices; and
- Strong cash flow measures and declining debt leverage.

Weaknesses:

- Absence of weather normalization and decoupling rate structures, which expose the company's earnings and cash flow to conservation and weather-related sales variations;
- Elevated projected capital expenditures of about $290 million per year;
- Moderate exposure to the effects of natural gas price volatility on PGA receivable balances and potential liquidity requirements; and
- Long-term capital or contracting requirements with regard to natural gas storage capability for the company's Arizona and Southern Nevada service areas.

Rationale

The ratings on Las Vegas, Nev.-based Southwest Gas Corp. reflect its strong business risk profile and aggressive financial risk profile. The ratings are based on the consolidated credit profile of its natural gas operations segment (87% of operating income in 2007) and its construction services business, Northern Pipeline Construction Co. (NPL; 13%).

Southwest Gas' strong business risk profile reflects a large, stable, residential, and commercial customer base of about 1.8 million customers, strong customer growth prospects in Arizona (54% of customers), Nevada (36%), and California (10%), the absence of competition, and relatively low operating risks. Challenges associated with improving its regulatory cost-recovery mechanisms, ownership of a small, unregulated construction and maintenance business, gradual reductions in total gas volumes, and limited geographic service territory temper the company's strong business profile.

The Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada, and the California Public Utilities Commission each regulate Southwest Gas. Each regulatory commission provides the company with various cost-recovery mechanisms. However, we view the ACC regulatory oversight as less supportive of credit than other jurisdictions due to its limitations on purchased-gas cost recoveries and rate design that is solely based on gas throughput. This type of rate design exposes the company to reduced cash flows as volumes decline related to conservation. Decoupling, an alternate rate design, separates the utility's margins and cash flow from commodity sales and encourages conservation. These mechanisms are currently under consideration as part of the company's most recent rate case.

Slowing customer growth, reduced total throughput, and improved rate design are among the reasons for Southwest

Gas' recent rate filings. While Southwest Gas' annual customer growth averaged more than 4% over the past five years, the company expects future growth to be only 1.5% to 3% due to the depressed real estate market conditions. Despite strong historical customer growth statistics, annual total consumption has nevertheless dropped 1% per year, on average, since 2003, due to conservation efforts, making rate design a key credit driver for the company.

Southwest Gas' nonregulated subsidiary, NPL, is not currently a significant rating factor because most of its contracts shield Southwest Gas from the majority of costs. In addition, about 20% of NPL's revenues are derived from Southwest Gas' gas operations.

Southwest Gas has an aggressive financial risk profile, with bondholder protection measures that are currently strong for the rating, which supports the positive outlook. We expect near-term performance to remain strong for the rating with additional improvements from customer growth and regulatory rate increases. As of Dec. 31, 2007, total debt, including operating leases and tax-affected pensions and post-retirement obligations, was about $1.5 billion with debt to capital of almost 60%. Benefitting from customer growth and regulatory rate increases, cash flow metrics have improved over the past few years, with 2007 adjusted funds from operations (FFO) to total debt of 20% and FFO interest coverage of about 4x, compared with 14% and 3.4x, respectively, in 2005.

Liquidity

Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses of liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.

Given the low-risk nature of Southwest Gas' regulated utility operations and healthy service territory, the company should generate reasonably stable cash flow. The company reported cash from operations of almost $350 million for 2007, which will not fully cover annual dividends (about $36 million), annual capital expenditures (about $300 million forecast for 2008 and about $550 forecast for 2009-2010 combined), and near-term debt maturities ($38 million due in 2008 and $10 million in 2009). To bridge the funding gap, the company expects to raise $70 million to $80 million through stock offerings, borrow under its revolving credit facility, or through other external means.

Outlook

The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Ratings Services' expectation that the company's improved financial performance could lead to a higher rating over the near term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

Accounting

Standard & Poor's adjusts Southwest Gas' financial statements for operating leases and pension and post-retirement obligations. The adjustment includes adding a debt equivalent, interest expense, and depreciation to the company's reported financial statements. As a result, debt equivalents of $24 million are added for operating leases and $90 million for pension and post-retirement obligations.

Due to the distortions in leverage and cash flow metrics caused by the substantial seasonal working-capital requirements of gas utilities, Standard & Poor's adjusts inventory and debt balances by netting the value of inventory against the outstanding commercial paper for regulated subsidiaries. This adjustment provides a more accurate view of the company's financial performance by reducing seasonality, where there is a very high likelihood of recovery. As inventories are depleted and accounts receivable are monetized, with support from commodity pass-through mechanisms, these funds reduce the utility's short-term borrowings.

Standard & Poor's views Southwest Gas' $100 million of trust-preferred securities as having "intermediate equity content". Under our hybrid criteria, we calculate the company's financial ratios with 50% of the outstanding balance attributed to debt and 50% to equity. Similarly, we treat 50% of the associated distributions as dividends and 50% as interest.

Southwest Gas prepares its financial statements using SFAS No. 71, "Accounting for Effects of Certain Types of Regulation." Consequently, Southwest Gas recorded certain regulatory assets and liabilities as of Dec. 31, 2007, of $218 million and $226 million, respectively. Net regulatory assets represent less than 1% of total capitalization.

Table 1

Southwest Gas Corp. -- Peer Comparison*

Industry Sector: Gas

	--Average of past three fiscal years--			
	Southwest Gas Corp.	**NiSource Inc.**	**CenterPoint Energy Resources Corp.**	**Atmos Energy Corp.**
Rating as of April 17, 2008	BBB-/Positive/--	BBB-/Stable/--	BBB/Positive/A-2	BBB/Positive/A-2
(Mil. $)				
Revenues	1,963.7	7,776.3	7,791.3	5,670.9
Net income from cont. oper.	70.3	303.0	229.0	150.7
Funds from operations (FFO)	256.0	867.3	524.7	411.6
Capital expenditures	327.2	697.9	564.0	411.1
Cash and investments	26.8	46.2	12.3	97.8
Debt	1,490.6	7,705.8	2,685.9	2,639.1
Preferred stock	50.0	27.0	0.0	0.0
Equity	910.5	4,946.5	2,948.7	1,674.3
Debt and equity	2,401.1	12,652.4	5,634.6	4,313.4
Adjusted ratios				
EBIT interest coverage (x)	2.2	2.1	2.9	2.7
FFO int. cov. (x)	3.7	2.8	3.6	3.5
FFO/debt (%)	17.2	11.3	19.5	15.6
Discretionary cash flow/debt (%)	(4.3)	(0.1)	(14.4)	(3.9)
Net cash flow/capex (%)	66.8	88.2	75.3	74.7
Debt/total capital (%)	62.1	60.9	47.7	61.2
Return on common equity (%)	8.2	5.8	7.9	9.3
Common dividend payout ratio (un-adj.) (%)	47.9	82.9	43.7	69.2
Ratios before adjustments for postretirement obligations				
Oper. income/sales (bef. D&A) (%)	18.8	19.8	9.5	10.4

Table 1

Southwest Gas Corp. -- Peer Comparison*(cont.)				
EBIT interest coverage (x)	2.2	2.1	2.9	2.6
FFO/debt (%)	17.9	11.4	19.9	16.8
Debt/EBITDA (x)	3.8	4.8	3.6	4.3
Debt/total capital (%)	60.0	59.1	47.0	59.2

*Fully adjusted (including postretirement obligations).

Table 2

Southwest Gas Corp. -- Financial Summary*					
Industry Sector: Gas					
	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB-/Positive/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--
(Mil. $)					
Revenues	2,152.1	2,024.8	1,714.3	1,477.1	1,231.0
Net income from continuing operations	83.2	83.9	43.8	56.8	38.5
Funds from operations (FFO)	290.6	260.0	217.4	252.0	228.5
Capital expenditures	344.7	343.0	294.1	301.9	239.8
Cash and investments	32.0	18.8	29.6	13.6	17.2
Debt	1,476.4	1,488.1	1,507.3	1,453.9	1,325.1
Preferred stock	50.0	50.0	50.0	50.0	50.0
Equity	1,033.7	951.4	746.4	684.6	619.3
Debt and equity	2,510.1	2,439.6	2,253.7	2,138.5	1,944.4
Adjusted ratios					
EBIT interest coverage (x)	2.5	2.4	1.8	2.0	1.7
FFO int. cov. (x)	4.0	3.7	3.4	3.9	3.8
FFO/debt (%)	19.7	17.5	14.4	17.3	17.2
Discretionary cash flow/debt (%)	(1.4)	(5.8)	(5.4)	(11.9)	(4.0)
Net cash flow/capex (%)	72.7	64.9	62.0	72.7	82.1
Debt/debt and equity (%)	58.8	61.0	66.9	68.0	68.2
Return on common equity (%)	8.7	9.8	5.7	8.4	5.9
Common dividend payout ratio (un-adj.) (%)	43.6	39.9	71.3	50.8	71.9
Ratios before adjustments for postretirement obligations					
Oper. income/revenues (bef. D&A) (%)	19.0	18.9	18.2	21.9	22.8
EBIT interest coverage (x)	2.4	2.4	1.8	2.1	1.7
FFO/debt (%)	20.3	18.2	15.2	18.2	17.8
Debt/EBITDA (x)	3.4	3.6	4.5	4.3	4.5
Debt/debt and equity (%)	57.3	59.3	63.7	64.5	65.0

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Southwest Gas Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

--Fiscal year ended Dec. 31, 2007--

Southwest Gas Corp. reported amounts

	Debt	Shareholders' equity	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	1,413.1	983.7	403.1	403.1	220.6	96.2	347.8	347.8	36.3	340.9
Standard & Poor's adjustments										
Operating leases	24.0	--	6.2	1.6	1.6	1.6	4.5	4.5	--	5.1
Intermediate hybrids reported as debt	(50.0)	50.0	--	--	--	(3.9)	3.9	3.9	3.9	--
Postretirement benefit obligations	89.2	--	5.4	5.4	5.4	--	8.9	8.9	--	--
Capitalized interest	--	--	--	--	--	1.3	(1.3)	(1.3)	--	(1.3)
Reclassification of nonoperating income (expenses)	--	--	--	--	6.6	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(73.2)	--	--
Total adjustments	63.3	50.0	11.5	7.0	13.6	(0.9)	16.0	(57.2)	3.9	3.8

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	1,476.4	1,033.7	414.6	410.1	234.2	95.3	363.8	290.6	40.1	344.7

*Southwest Gas Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of April 24, 2008)*

Southwest Gas Corp.	
Corporate Credit Rating	BBB-/Positive/--
Preferred Stock	
Local Currency	BB
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
13-Mar-2007	BBB-/Positive/--

Ratings Detail (As Of April 24, 2008)*(cont.)	
11-Aug-2003	BBB-/Stable/--
01-Feb-2001	BBB-/Negative/--
Financial Risk Profile	Aggressive

Debt Maturities

As of Dec. 31, 2007:
2008: $38.1 mil.
2009: $10.4 mil.
2010: $5.4 mil.
2011: $202.6 mil.
2012: $350.1 mil.
Thereafter: $697.0 mil.

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

ATTACHMENT C

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-05-0816

DIRECT TESTIMONY

OF

STEPHEN G. HILL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 18, 2006

Schedule 8 attached to this testimony shows the detail regarding the CAPM analysis. The average beta coefficients for the electric utility sample group was 0.83. Schedule 8 shows a CAPM cost of capital for the electric companies ranging from 9.23% to 10.56%.

Schedules 9 and 10 shows the theoretical basis and the data and calculations, respectively, for the Modified Earnings Price Ratio (MEPR) analysis. The MEPR analysis indicates a current cost of equity capital for electric companies in a narrow range from 8.79% to 9.13%. Finally, Schedule 11 attached to this testimony contains the supporting detail for the Market-to-Book Ratio (MTB) analysis, which indicates a current cost of equity capital for the electric utility companies of 9.31% (near-term) to 9.38% (long-term).

C. SUMMARY

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR EQUITY CAPITAL COST ANALYSES FOR THE SAMPLE GROUP OF SIMILAR-RISK ELECTRIC UTILITY COMPANIES.

A. My analysis of the cost of common equity capital for the sample group of electric utility companies is summarized in the table below.

METHOD	Electric Utility Companies
DCF	9.44%
CAPM	9.23%/10.56%
MEPR	9.13%/8.79%
MTB	9.31%/9.38%

For the electric utility sample group, the DCF result is 9.44%. In addition, the corroborating cost of equity indications (MEPR, MTB, and CAPM) indicate that DCF result is reasonable. Averaging the lowest and highest results of all the corroborative analyses for the electric companies produces and equity cost range of 9.11% to 9.69%, with a mid-point of 9.40%, only 4 basis points below the DCF result.

Therefore, weighing all the evidence presented herein, my best estimate of the cost of equity capital for a company like Arizona Public Service, facing similar risks as this group of electric utilities, ranges from 9.25% to 9.75%, with a mid-point of 9.50%.

Q. ARE THERE OTHER FACTORS TO BE CONSIDERED BEFORE DETERMINING A POINT-ESTIMATE FOR APS WITHIN A REASONABLE RAGE FOR SIMILAR-RISK FIRMS?

A. Yes. First, the electric sample group companies have similar operating risk to APS. The average S&P business risk score of my sample of electric utilities is 6—the same as that for APS. Therefore, on that basis there would be no reason to adjust the equity return from the mid-point of a reasonable range. However, because the capital structure I recommend for ratesetting purposes contains considerably more common equity and less debt than average for the sample group, APS, prospectively will have less financial risk than the sample group and should be awarded an equity return below the mid-point of a reasonable range.

Q. IS THERE A RECOGNIZED METHOD WITH WHICH DIFFERENCES IN FINANCIAL RISK CAN BE QUANTIFIED?

A. Yes. The cost of equity capital is affected by the capital structure a company employs. When a company increases the proportion of debt in its capital structure, it increases the riskiness of its equity. Financial risk (created by the use of debt in the capital structure) causes investors to demand a higher rate of return; that is, financial risk increases the cost of equity capital.

The impact of debt leverage on the cost of equity capital can be approximated through an examination of the changes in beta, which occur when leverage is increased or decreased. The Value Line betas for the sample companies used in my cost of capital analysis in this proceeding reflect the market's (investors') perception of both the business risks and the financial risks of a firm. That is, one portion of the beta of a firm is related to the business risk of the firm (the risk inherent in its operations) and one portion of the beta is related to the financial risk of that firm (the risk associated with the use of debt). Therefore, if a firm elects to finance its operations with debt as well as equity, the beta coefficient of that firm will reflect both the business and financial risk. When a firm uses debt to finance its operations, the beta can also be referred to as a "levered" beta (i.e., a beta coefficient that includes the impact of debt leverage).

The average beta coefficient of the sample group of utilities can be "unlevered." That is, the beta-risk related to the level of debt capital used by the firm can be removed. "Unlevering the betas" amounts to estimating what the average beta would be if the companies were financed entirely with equity capital. Equation (2) is used to estimate the unlevered beta for a firm or a group of similar-risk firms.[19]

$$\beta_U = \frac{\beta_{Measured}}{(1+(1\text{-}t)D/E)} \qquad (2)$$

Equation (2) indicates that an estimate of the unlevered beta (β_U) of a firm can be calculated by dividing the measured beta ($\beta_{Measured}$, e.g. the beta coefficient reported by investor services such as Value Line) by one plus the average debt-to-equity ratio, adjusted to account for taxes. The debt-to-equity ratio is measured using the average market value of the sample group's common equity capital. Once the unlevered beta for the firm (or, in this case, for the sample group of market-traded utility companies) is calculated, the beta coefficient is "re-levered" and adjusted to conform to the less leveraged capital structure of APS, which contains 50% common equity. The formula used to "re-lever" the utility betas is shown below.

$$\beta_{Relevered} = \beta_U\,(1+(1\text{-}t)D/E) \qquad (3)$$

[19]Equation (1) is a version of the Hamada equation which combines the Miller-Modigliani theories regarding capital structure and the logic of the CAPM: Hamada, R.S., "Portfolio Analysis, Market equilibrium and Corporation Finance," *Journal of Finance*, March 1969, pp. 13-31.

Equation (3) states that the relevered beta equals the unlevered beta (β_U) multiplied times one plus the target debt-to-equity ratio (in this case APS's ratemaking capital structure—50% equity/50% debt), again adjusted for taxes.

Schedule 12 shows that, the average capital structure of the sample group of electric companies used to estimate the cost of equity capital in my direct testimony consists of 45.13% common equity and 54.69% fixed-income capital. That capital structure, adjusted to market levels by an average 1.69 market-to-book ratio and accounting for a 35% tax rate, produces an average value for (1-t)D/E in Equation (2) of 0.53.

Schedule 12 shows further that the measured (average Value Line) beta coefficient of the sample group of gas utility firms is 0.83, and the <u>unlevered</u> beta coefficient of those firms (i.e., what the average beta would be if those firms were financed entirely with common equity) is 0.54. When that beta is "relevered" using the methodology described above to conform to APS's ratemaking capital structure, the resulting average beta coefficient is 0.75, an decrease in beta of 0. 079 due to the sample group's lower average equity capitalization ["measured" beta of 0.83 vs. "relevered" beta of 0.751].

Finally, with the increase in beta determined, the CAPM can be used to estimate the impact of that adjustment on the cost of capital. A review of the CAPM equation (Equation (i) in Appendix D) indicates that the beta coefficient is multiplied by the market risk premium (r_m - r_f) as a step in the determination of the cost of capital. Therefore, it is possible to measure the impact of an adjustment to beta by multiplying the difference in the measured and relevered betas of the electric companies by the market risk premium.

As I noted in my discussion of the CAPM analysis in Appendix D, the long-term historical market risk premium provided by Ibbotson Associates' historical database is 5% to 6.6%. I also discuss the fact that the most recent research by Fama and French regarding the market risk premium indicates that the Ibbotson historical risk premium data overstate investor expectations, which are a return of 2.5% to 4.5% over the risk-free rate of interest.[20] Ibbotson has also published a paper recently, which indicates that investors can expect returns in the future of from 4% to 6% above the risk-free.[21] Therefore, for purposes of this analysis, I will use a range of market risk premium from 4% to 6%.

As shown in Schedule 12, an decrease in the average beta coefficient of 0.079, multiplied by a market risk premium ranging from 4% to 6%, indicates an decrease in the cost of equity capital due to reduced leverage at APS of from 32 to 48 basis points (0.079 x 4%-6% = 0.317%-0.476%).

The mid-point of the cost of common equity for the electric utility sample group, presented previously is 9.50%. Although the equity return decrement indicated is slightly higher, recognizing the decrease in financial risk due to reduced leverage at APS, a cost of equity of 9.25% for ratemaking purposes is reasonable. That represents a decrease in the cost of equity for APS (with a 50% common equity ratio) of 25 basis points below the mid-point of a reasonable range for electric utility operations, which are capitalized on average with about 45% common equity.

It is important to emphasize here that if the Commission elects to utilize the Company's requested 54.5% common equity ratio for ratesetting purposes, rather than the 50% I recommend, the equity return decrement due to lower financial risk would have to be greater than the 25 basis points I recommend. If a "target" capital common equity ratio of 54.5% were substituted in Schedule 12, the "relevered" beta would be 0.72, rather than the 0.75 used in my analysis. Also the indicated reduction in the cost of equity would range from 0.45% to 0.68%. Those data indicate that if this Commission elects to set rates for APS using its requested capital structure, an equity return decrement of 50 basis points would be reasonable.

Q. DOES THAT 9.25% EQUITY COST ESTIMATE INCLUDE AN INCREMENT FOR

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[20] Fama, E., French, K., "The Equity Premium," *The Journal of Finance*, Vol. LVII, No. 2, April 2002, pp. 637-659.

[21] Ibbotson, R, Chen, P., "Long-Run Stock Returns: Participating in the Real Economy," *Financial Analysts Journal*, January/February 2003, pp. 88-89.

FLOTATION COSTS?

A. No, it does not.

Q. CAN YOU PLEASE EXPLAIN WHY AN EXPLICIT ADJUSTMENT TO THE COST OF EQUITY CAPITAL FOR FLOTATION COSTS IS UNNECESSARY?

A. An explicit adjustment to "account for" flotation costs is unnecessary for several reasons. First, it is often said that flotation costs associated with common stock issues are exactly like flotation costs associated with bonds. That is not a correct statement because bonds have a fixed cost and common stock does not. Moreover, even if it were true, the current relationship between the electric utility sample group's stock price and its book value would indicate a flotation cost reduction to the market-based cost of equity, not an increase.

When a bond is issued at a price that exceeds its face (book) value, and that difference between market price and the book value is greater than the flotation costs incurred during the issuance, the embedded cost of that debt (the cost to the company) is *lower* than the coupon rate of that debt.

In the current economic environment for the electric utility common stocks studied to determine the cost of equity in this proceeding, those stocks are selling at a market price 69% above book value. (Exhibit__(SGH-1), Schedule 4, p. 1) The difference between the market price of electric utility stock and book value dwarfs any issuance expense the companies might incur. Therefore, if common equity flotation costs were exactly like flotation costs with bonds, then, if an explicit adjustment to the cost of common equity were necessary, it should be downward, not upward.

Second, flotation cost adjustments are usually predicated on the prevention of the dilution of stockholder investment. However, the reduction of the book value of stockholder investment due to issuance expenses can occur only when the utility's stock is selling at a market price at to or below its book value. As noted, the companies under review are selling at a substantial premium to book value. Therefore, every time a new share of that stock is sold, existing shareholders realize an *increase* in the per share book value of their investment. No dilution occurs, even without any explicit flotation cost allowance.

Third, the vast majority of the issuance expenses incurred in any public stock offering are "underwriter's fees" or "discounts". Underwriter's discounts are not out-of-pocket expenses for the issuing company. On a per share basis, they represent only the difference between the price the underwriter receives from the public and the price the utility receives from the underwriter for its stock. As a result, underwriter's fees are not an expense incurred by the issuing utility and recovery of such "costs" should not be included in rates.

In addition, the amount of the underwriter's fees are prominently displayed on the front page of every stock offering prospectus and, as a result, the investors who participate in those offerings (e.g., brokerage firms) are quite aware that a portion of the price they pay does not go to the company but goes, instead, to the underwriters. By electing to buy the stock with that understanding, those investors have effectively accounted for those issuance costs in their risk-return framework by paying the offering price. Therefore, they do not need any additional adjustments to the allowed return of the regulated firm to "account" for those costs.

Fourth, my DCF growth rate analysis includes an upward adjustment to equity capital costs which accounts for investor expectations regarding stock sales at market prices in excess of book value, and any further explicit adjustment for issuance expenses related to increases in stock outstanding is unnecessary.

Fifth, research has shown that a specific adjustment for issuance expenses is unnecessary[22]. There are other transaction costs which, when properly considered, eliminate the need for an explicit issuance expense adjustment to equity capital costs. The transaction cost that is improperly ignored by the advocates of issuance expense adjustments is brokerage fees. Issuance expenses occur with an initial issue of stock in a primary market offering. Brokerage fees occur in the much larger secondary market

[22] "A Note on Transaction Costs and the Cost of Common Equity for a Public Utility," Habr, D., National Regulatory Research Institute Quarterly Bulletin, January 1988, pp. 95-103.

where pre-existing shares are traded daily. Brokerage fees tend to increase the price of the stock to the investor to levels above that reported in the Wall Street Journal, i.e., the market price analysts use in a DCF analysis. Therefore, if brokerage fees were included in a DCF cost of capital estimate they would raise the effective market price, lower the dividend yield and lower the investors' required return. If one considers transaction costs that, supposedly, raise the required return (issuance expenses), then a symmetrical treatment would require that costs that lower the required return (brokerage fees) should also be considered. As shown by the research noted above, those transaction costs essentially offset each other and no specific equity capital cost adjustment is warranted.

Q. WHAT IS THE OVERALL COST OF CAPITAL FOR APS's INTEGRATED UTILITY OPERATIONS, BASED ON AN ALLOWED EQUITY RETURN OF 9.25%?

A. Schedule 13 attached to my testimony shows that an equity return of 9.25%, operating through an appropriate ratemaking capital structure of 50% equity and 50% debt, and the Company's requested embedded capital cost rates, produces an overall return of 7.33% for APS. Schedule 13 also shows that a 7.33% overall cost of capital affords the Company an opportunity to achieve a pre-tax interest coverage level of 3.85 times.

According to APS's 2005 S.E.C. Form 10-K (Exhibit 12), the pre-tax interest coverage over the past five years has averaged 2.94x and has ranged from 2.81x to 3.17x. The return I recommend would allow the Company the opportunity to improve its historical average interest coverage. Therefore, the equity return I recommend fulfills the legal requirement of <u>Hope</u> and <u>Bluefield</u> of providing the Company the opportunity to earn a return which is commensurate with the risk of the operation and serves to support and maintain the Company's ability to attract capital.

V. COMPANY COST OF CAPITAL TESTIMONY

Q. HOW HAS COMPANY WITNESS AVERA ESTIMATED THE COST OF EQUITY CAPITAL IN THIS PROCEEDING?

ARIZONA PUBLIC SERVICE COMPANY
LEVERAGE/BETA ADJUSTMENT TO THE COST OF EQUITY CAPITAL

COMPANY	COMMON EQUITY	FIXED INCOME CAPITAL	M/B RATIO	MKT. VALUE DEBT(1-t)/EQ.
Central Vermont P. S.	63.00%	37.00%	1.05	0.36
FirstEnergy Corp.	45.00%	55.00%	1.77	0.45
Green Mountain Power	56.00%	44.00%	1.30	0.39
Progress Energy	41.00%	59.00%	1.29	0.73
Ameren Corp.	50.00%	50.00%	1.58	0.41
Cleco Corporation	52.00%	48.00%	1.52	0.39
DPL, Inc.	35.00%	65.00%	4.51	0.27
Empire District Electric	46.00%	54.00%	1.37	0.56
Entergy Corp.	46.00%	54.00%	1.77	0.43
Hawaiian Electric	37.00%	63.00%	1.77	0.63
PNM Resources	38.00%	62.00%	1.31	0.81
Pinnacle West Capital	48.00%	52.00%	1.11	0.63
Unisource Energy	32.00%	68.00%	1.64	0.84
AVERAGES	45.31%	54.69%	1.69	0.53
TARGET CAP. STRUCTURE	50.00%	50.00%	1.69	**0.38**

AVERAGE (LEVERED) UTILITY BETA = 0.83

Beta (Unlevered) = Beta (Levered)/(1+D(1-t)/E)

Beta (Unlevered)= 0.83/(1+.53)= **0.54**

Beta (Relevered)= Beta (Unlevered)*(1+D(1-t)/E)

Beta (Relevered)= 0.54(1.38)= **0.75**

IMPACT ON COST OF EQUITY CAPITAL

	Measured Beta	0.830
	Relevered Beta	0.751
[1]	Diff. in Beta	0.079
[2]	Market Risk Premium (rm-rf) =	4% to 6%

Average Cost of equity impact = [1] x [2] = **0.32% to 0.48%**

ATTACHMENT D

Roger A. Morin, PhD

NEW
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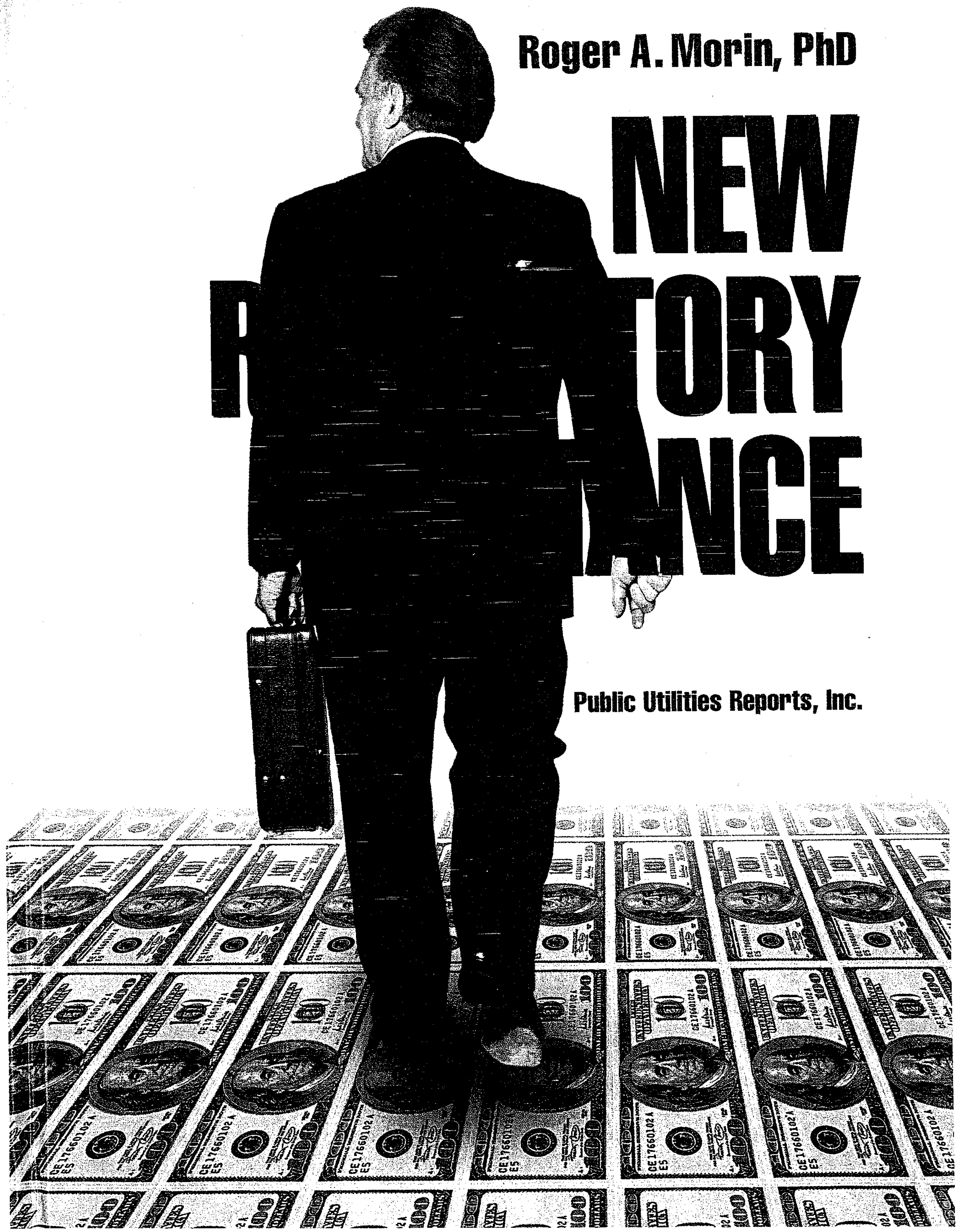

Public Utilities Reports, Inc.

DCF Growth Rate Check

As a reasonableness check on the DCF growth rate, the growth rate in dividends can be verified using the following relationship:[16]

Dividend Growth = Risk-free Return + Risk Premium − Dividend Yield

For example, let us say that the yield on Treasury bonds as a proxy for the risk-free return is 5%, the utility risk premium is 5.5% derived from a Capital Asset Pricing Model (CAPM) analysis discussed in earlier chapters, and the expected dividend yield for the utility industry is 4.5%. Substituting these values in the above relationship, we obtain a dividend growth expectation of 6.0% as follows:

Dividend Growth = 5.0% + 5.5% − 4.5% = 6.0%

9.6 Growth in the Non-Constant DCF Model

Although the constant growth DCF model does have a long history, analysts, practitioners, and academics have come to recognize that it is not applicable in many situations. A multiple-stage DCF model that better mirrors the pattern of future dividend growth is preferable. There is a growing consensus and ample empirical support that the best place to start is with security analysts' forecasts, that is, assume that dividend policy is relatively constant and use analyst forecasts of earnings growth as a proxy for dividend forecasts. The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate. Accordingly, multiple-stage DCF models of this transition are available and were described in Chapter 8. It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.

A reasonable alternative to the constant growth DCF model is to use a multiple-stage DCF model that more appropriately captures the path of future dividend

[16] Equating the expected return from the standard DCF equation and the required return from the CAPM equation:

$$K = D_1/P + g = R_f + \text{Risk Premium}$$
$$K = D_1/P + g = R_f + \beta(R_m - R_f) \text{ from the CAPM}$$

Solving for g:

$$g = R_f + \beta(R_m - R_f) - D_1/P$$

ATTACHMENT E

April 2006

Briefing Paper

Revenue Decoupling for Natural Gas Utilities

The National Regulatory Research Institute

Ken Costello
Senior Institute Economist

EXECUTIVE SUMMARY

High natural gas prices have provoked recent proposals to modify long-held ratemaking practices for gas utilities. Energy conservation has emerged as an option to address the serious problem of consumers suffering from accelerating gas bills. With a heightened emphasis on energy conservation, gas utilities have expressed concern about the implications of lower gas usage for their financial stability. In response to this situation, gas utilities as well as conservationists have advocated a ratemaking mechanism generically labeled revenue decoupling (RD). From the perspective of gas utilities, RD can prevent financial erosion from future reductions in consumption by gas consumers. Conservationists view RD as indispensable in eliminating the disincentive for gas utilities to promote energy conservation under standard ratemaking.

This briefing paper reviews the activities to date on the application of RD for gas utilities. Five gas utilities presently have commission-approved RD mechanisms. Several others have RD proposals pending before their state commissions. Consumer groups and others have posed several arguments in disfavor of RD. Some state commissions have endorsed RD while others have opposed it. This paper lists the arguments on both sides together with an assessment of their merits.

This briefing paper takes a balanced perspective of RD by directing attention to both the upside and downside of this ratemaking mechanism. It specifically analyzes the efficacy of RD in fostering prevailing regulatory and ratemaking objectives. The paper's primary intent is to make state commissions as well as other policymakers better informed on the likely outcomes of RD. While this paper concentrates on the natural gas industry, much of its content applies equally to both the electric and water industries.

Contents

The author appreciates the helpful comments of Commissioner Richard Morgan, District of Columbia Public Service Commission, Robert Harding, Minnesota Public Utilities Commission, Bob Pauley, Indiana Utility Regulatory Comnmission, James F. Wilson, LECG LLC., and Dr. Vivian Witkind Davis on earlier drafts of this paper.

06-06

TABLE 2
EXPECTED OUTCOMES FROM REVENUE DECOUPLING

Reduced overall risk to the utility	Little effect on incentives for customer-initiated conservation
Less incentive for utility to promote sales, and less disincentive to promote energy efficiency	Increased rate volatility (although probably small relative to the volatility of the gas commodity cost)
Base rates inversely related to actual sales between rate cases	Effect similar to shifting recovery of fixed costs to customer charge, except for possible intra-class subsidy effect
Base rates would tend to be higher (as the utility's average cost would increase, assuming lower sales), although some offset from a possible lower cost of capital)	Uncertain of the risk and overall economic welfare effect on consumers

Source: Author's construct.

standard ratemaking, rate design is the third step in designing rates (the first two are revenue requirement and cost allocation). Rate design involves setting actual billing elements (for example, the customer charge and the volumetric charge) to recover revenues by customer class commensurate with the determined costs allocated to each class. As a rate design, RD would allow a utility to recover the same revenues for distribution service irrespective of actual sales.[48] In effect, RD predetermines how much in revenues the utility will collect from those customer classes subject to the mechanism. This fixity of revenues reduces the risk to a utility from under-recovering its revenues and suffering a cash flow deficiency.

Expected Outcomes from Revenue Decoupling

Table 2 lists the expected outcomes from revenue decoupling. *First, it would obviously reduce a utility's risk from sales fluctuations.* For a utility, this creates more stability in revenues, cash flows and earnings. Under revenue decoupling, for example, revenue volatility for the utility caused by a downturn in the local economy or higher gas prices leading to fewer sales would be less pronounced. Although a utility's overall risk would seemingly decline, exactly by how much would require a sophisticated quantitative analysis. In the order approving Piedmont Gas' revenue decoupling proposal, the North Carolina Utilities Commission said that "Piedmont argues that there is no evidence of reduced risk to shareholders, but the Commission disagrees on the basis of the Company's own case...In a period of declining per-customer usage, a mechanism that decouples recovery of margin from usage, without requiring the utility to file frequent rate cases or increase unpopular fixed charges, clearly reduces shareholder risk."[49] Because of the company's RD mechanism (Rider 8), the Maryland Public Service Commission reduced

Although a utility's overall risk might decline, determining how much would require sophisticated quantitative analysis.

Essentially, the utility would become indifferent to its sales.

If a utility's customers collectively use less gas, rates could rise. But reduced benefits would be small relative to realized benefits.

the authorized rate of return on equity for Baltimore Gas and Electric by 50 basis points to reflect reduced revenue risk for the utility.

Second, revenue decoupling reduces a utility's incentive to grow its sales, or to offer new services, and, simultaneously, provides a lesser disincentive to promote energy efficiency. Essentially the utility becomes indifferent to the level of its sales, assuming the utility achieves the same earnings irrespective of actual sales. This is probably more valid in the short term. In the longer term, a utility may prefer promoting sales to the extent it helps support new capital expenditures, which are rate based and consequently add to the utility's earnings.

Third, between rate filings revenue decoupling would result in an inverse relationship between the utility's base rate and actual sales. For example, if sales drop because of an aggressive effort by the utility to promote energy conservation, under revenue decoupling this would increase the base rate in the absence of a rate filing.

Fourth, as a corollary to fewer sales resulting, the utility's short-run average cost for non-gas service would tend to be higher.[50] Logically, as fixed costs cover less sales, average cost would rise. The assumption of lower sales seems valid even if the utility has no special energy-efficiency initiatives; the reason is that RD would make the utility less motivated than otherwise to increase its sales through promotional practices. Since non-gas service reflects a fixed cost business, any sales decline induced by revenue decoupling would have little effect on a utility's short-run non-gas costs. This outcome is implicit under a RD mechanism, as rates adjust upward to compensate for the utility's higher average cost stemming from fewer sales.

Fifth, RD would probably have little effect on customer-initiated energy efficiency.[51] The benefits to a customer from using less natural gas sums to the delivered price (i.e., the base rate plus the purchased gas costs) times the amount of gas saved. For an individual customer consuming less gas, RD would have a miniscule effect on a utility's rates. In other words, the presumption here is that an individual customer curtailing her use of natural gas by itself would have no visible effect on rates since the lost revenue to the utility would be imperceptible relative to total revenues. On the other hand, if a utility's customers collectively consume less gas, this could cause rates to rise. In this event, the benefits to individual customer from energy conservation could somewhat decline, but even here the reduced benefits would be small relative to the size of the realized benefits. In recent years, for many utilities the base rate for natural gas to residential customer has fallen to less than 30 percent of the total delivered price.[52] Assuming that RD causes the base rate to increase by 2 percent with the base rate representing 30 percent of the delivered price, customers would see an aggregated rate increase of 0.6 percent.[53] Consequently, customers would realize 0.6 percent less benefits from energy conservation.[54] As

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-07-0504

SURREBUTTAL TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MAY 27, 2008

SURREBUTTAL TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name for the record.

A. My name is Rodney Lane Moore.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on March 28, 2008 and additional direct testimony regarding rate design on April 11, 2008.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments pertaining to adjustments I sponsored in my direct testimony.

SUMMARY OF ADJUSTMENTS

Q. What areas will you address in your surrebuttal testimony?

A. My surrebuttal testimony will address the following RUCO proposed adjustments:

Rate Base:

Adjustment No. 4 – Accumulated Deferred Income Taxes Associated With the Management Incentive Plan and the Supplemental Executive Retirement Plan;

Adjustment No. 5 – Allowance For Working Capital.

Operating Income:

Adjustment No. 1 – Annualized Labor and Labor Loading;

Adjustment No. 6 – Unnecessary Miscellaneous Expenses;

Adjustment No. 7 – Incentive Compensation;
Adjustment No. 8 – Supplemental executive Retirement Plan;
Adjustment No. 9 – Employee Recognition;
Adjustment No. 10 – Uncollectible Expense;
Adjustment No. 12 – Yuma Manors Pipe Replacement Expenses; and
Adjustment No. 13 – Income Tax Calculation.

To support the adjustments in my surrebuttal testimony, I have revised specific direct testimony Schedules and prepared Surrebuttal Schedules numbered SURR RLM-1, SURR RLM-2, SURR RLM-6, SURR RLM-7, SURR RLM-8, and SURR RLM-17 through SURR RLM-20, which are filed concurrently in my surrebuttal testimony.

These Schedules quantify the adjustments recommended in RUCO's surrebuttal testimonies and consist of revisions to:

1. Accumulated Deferred Income Tax ("ADIT") associated with Management Incentive Plan ("'MIP") and the Supplemental Executive Retirement Plan ("'SERP") accept the Company's adjustment;
2. Lead/Lag Study used to calculate the Allowance For Working Capital to accept the Company's adjustment;
3. Unnecessary Miscellaneous Expenses to remove double counted expenditures;
4. Uncollectible Expenses to accept the Company's adjustment;
5. Yuma Manors Pipe Replacement Expenses as a conforming adjustment to the Company's Revised Rebuttal position;

6. Income Tax Expense to reflect changes in the operating expenses associated with the surrebuttal adjustments; and
7. Rate Design, Proof of Recommended Revenue and Typical Bill Analysis to reflect changes in the operating expenses associated with the surrebuttal adjustments.

RATE BASE

RUCO Rate Base Adjustment No. 4 – ADIT Associated With MIP and SERP

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the test-year ADIT?

A. Yes. The Company's ADIT was recorded in an account that is not a component of SWG's rate base.

Therefore, as shown on Surrebuttal Schedule SURR RLM-2, RUCO adjusted the ADIT to reflect the Company's level of ADIT as filed.

RUCO Rate Base Adjustment No. 5 – Allowance For Working Capital

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the allowance for working capital?

A. Yes. The Company accepted two adjustments RUCO made to the lead-lag study. First, the Company agrees with RUCO that the interest expense on the preferred stock should be included in the lead/lag study, albeit at 79.50 days as opposed to 82.73 days and disagreed with the inclusion of interest on customer deposits. As shown on Surrebuttal Schedule SURR RLM-6, page 2, RUCO removed $1,915,314 of interest on customer deposits, adjusted the interest expense lag from 82.73 days to 79.50 days to include the impact of preferred securities. Second, the Company agreed with RUCO's adjustment to include the lag associated with revenue taxes. However, the Company has calculated a revenue tax lag of 45.24 days versus the 51.75 days recommended by RUCO. The Company's 45.24 days is based on the premise that the revenue taxes payable monthly are paid on the same date as associated revenue is received (see Company Rebuttal Exhibit RAM-3). However, through discovery the Company provided information to the contrary and inherently there is approximately an additional lag of 14 days between the payment of the monthly revenue-based taxes and the date the revenue is received. This 14-day lag computes to an overall revenue tax lag of 57.51 days versus the Company's rebuttal filing of 45.24 days. I have also made this adjustment on Schedule SURR RLM-6, page 2.

OPERATING INCOME

Operating Income Adjustment No. 1 – Annualized Labor and Labor Loading

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to annualize the labor and labor loading expenses?

A. No. As stated in my direct testimony, the inclusion of the June 2008 wage increase has the effect of triple-counting the increases in the salary and wage accounts - once for annualization of the test-year salaries, a second time for the post test-year 2007 three percent increase, and a third time for the 2008 increase. The Company's annualization adjustment to reflect estimated levels that will be in effect in June 2008 creates a mismatch between rate base, revenues and expenses at the end of the test year. If the Commission were to authorize rate recovery of the June 2008 payroll increases, the Company would be creating biased rates by picking and choosing which rate base, expense and revenue items it will reflect on an actual, projected or annualized basis. RUCO has allowed the test-year annualization as well as the post test-year 2007 wage increase, which is consistent with previous RUCO filings when the wage increase falls within a few months outside of the test year, but believes that a third proforma increase in 2008 is unwarranted.

Operating Income Adjustment No. 6 – Unnecessary Miscellaneous Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment of unnecessary miscellaneous expense?

A. Yes, the Company has provided information indicating RUCO's adjustment double counted certain expenditures related to employee recognition gift certificates.

Therefore, as shown on Schedule SURR RLM-8, column (G), I revised the unnecessary miscellaneous expense adjustment to recognize the double count, which increased test-year operating expenses by $19,160.

However, as for the remainder of the adjustment, RUCO and the Company have a philosophical difference as to the appropriateness of certain expenditures. RUCO does not believe that gift certificates, office refreshments, meals during meetings and extravagant off-site meetings are necessary in the provisioning of natural gas service to its customers.

Operating Income Adjustment No. 7 – Incentive Compensation

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment on incentive compensation?

A. No, for the reasons outlined in my direct testimony. Consistent with the Commission's Decisions on incentive compensation expense as set forth in Decision No. 70011, dated November 27, 2007 (the recent UNS Gas rate case); and the Decision (No. unavailable at filing) in the very recent UNS Electric rate case, RUCO recommends a 50/50 sharing of the incentive compensation expense.

A 50/50 sharing represents a reasonable balancing of the interests between ratepayers and shareholders. The incentive program is comprised of elements that relate to the Company's financial performance and cost containment goals, matters that primarily benefit shareholders; plus elements based on meeting customer service goals, which offers an opportunity for the Company's customers to benefit from improved performance.

Operating Income Adjustment No. 8 – SERP

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the SERP?

A. No, RUCO's position is unchanged – the ratepayers should not be responsible for paying the cost of supplemental benefits to a small select group of high-ranking officers of the Company.

However, RUCO does allow the full costs of the Company's stock option compensation to be included in test-year expenses.

It seems disingenuous in the present climate of spiraling utility costs to request that the ratepayers be burdened with the cost of this elite retirement plan for an exclusive group of employees who are already receiving lucrative salaries and benefits.

As stated in my direct testimony, the Commission agreed with RUCO that SERP expenses should not be the burden of ratepayers. In Southwest Gas' last rate case (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses. In Arizona Public Service's most recent rate case, (Decision No. 69663, dated June 28, 2007), the Commission voted to disallow SERP. The Commission voted to disallow SERP in the UNS Gas rate case (Decision No. 70011, dated November 27,2007). Moreover, the Decision (No. unavailable at filing) in the very recent UNS Electric rate case also disallows SERP. I see no reason to depart from this precedent; therefore, RUCO recommends the removal of the test-year cost of the SERP from operating expenses.

RUCO has made no surrebuttal adjustment to the SERP as filed in direct testimony.

<u>Operating Income Adjustment No. 9 – Employee Recognition</u>

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to employee recognition expenses?

A. No. RUCO does not deny the importance for SWG to have proactive programs and policies on safety, productivity and cost containment. Where RUCO differs, is the necessity to burden ratepayers with the expense incurred by the Company in offering additional compensation to its employees to perform work functions, some of which are county mandated, that should be considered a condition of employment.

<u>Operating Income Adjustment No. 10 – Uncollectible Expense</u>

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to test-year uncollectible expenses?

A. Yes, the Company's rebuttal testimony, workpapers and 2008 data illustrate that annual uncollectible expenses are trending upwards as a percentage of annual revenues.

RUCO will accept the Company's adjustment as filed. Therefore, as shown on Schedule SURR RLM-8, Column (K), I removed the adjustment.

Operating Income Adjustment No. 12 – Yuma Manors Pipe Replacement Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its operating income adjustments?

A. Yes. RUCO is making a conforming adjustment to include the test-year reduction in operating expenses proposed by the Company. SWG identified costs related to the replacement of steel pipe to the Manors subdivision in Yuma that SWG considered to be over and above those that it would have experienced had the replacement took place over a more routine time period.

RUCO accepts the expenses identified by the Company in its response to Commission Staff's data request 13.21 as those costs that are over and above what would have been experienced had the replacement been done in a more routine manner. The adjustment reduces gross plant by $320,779 for capitalized overtime and shift premium. The adjustment also reduces property tax expense by $8,499 and $15,175 in depreciation expense related to the $320,779 plant reduction.

Therefore, as shown on Schedules SURR RLM-2, Column (B), line 1 and SURR RLM-8, Column (M), this adjustment decreased test-year rate base by $320,779 and operating expenses by $23,674.

Operating Income Adjustment No. 13 – Income Tax Expense

Q. What adjustments have you made to the test-year Income Tax Expense account?

A. As shown on Schedule SURR RLM-17, I recalculated total test-year income taxes to reflect calculations based on my surrebuttal adjusted test-year revenue and expenses.

As shown on Schedule SURR RLM-8, column (Q), this adjustment increases the Company's adjusted test-year expenses by $2,825,460. This is an income tax decrease of $292,784 from the $3,118,244 increase recommended in my direct testimony.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. As shown on Schedule SURR RLM-19, I maintained the same set of bill determinants (i.e. test-year customer bill counts and therms consumed) as recommended in my direct testimony. After reviewing the Company's rebuttal testimony, I did not accept SWG's revised bill determinants as adjusted for declines in average weather normalized consumption through March 2008. The Company's proposed rebuttal post test-year bill count adjustment will result in mismatches in test-year elements. Furthermore, biased rates will result if the Commission were to recognize post test-year declines in consumption due to conservation; yet ignore post test-year increases in consumption due to customer growth. An in-depth discussion of RUCO's proposed rate design is contained in the surrebuttal testimony of RUCO witness, Ms Diaz Cortez. In summary, for residential customers, RUCO proposes a monthly basic service charge of $11.52 and a commodity charge of $0.55455 for all therms consumed.

PROOF OF RECOMMENDED REVENUE

Q. Have you revised your additional direct testimony Schedule to present proof of your revised surrebuttal recommended revenue?

A. Yes, I have. Proof that RUCO's direct testimony recommended rate designs would produce the revised surrebuttal recommended required revenue as illustrated, is presented on Schedule SURR RLM-19.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for G-5 residential customers with various levels of usage is presented on Schedule SURR RLM-20.

Q. Please provide an excerpt of RUCO's rate structure that illustrates RUCO's rate design goals as set forth in the testimony of Ms. Diaz Cortez that captures these fundamental changes in SWG's current rate design.

A. Schedule SURR RLM-20 provides an extensive breakdown of the effects of RUCO's proposed rates on the G-5 Residential Customer.

Below is a chart gleaned from Schedule SURR RLM-19 comparing SWG's proposed rates to RUCO's proposed annual rates:

<u>SWG Proposed Rates and Charges</u>

Basic Monthly Service Charge		$12.80
Non-Weather Sensitive Use –Charge Per Therm		
Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.88069	$0.60996	$1.49065
Weather Sensitive Use –Charge Per Therm		
Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.00	$1.49065	$1.49065

<u>RUCO Proposed Rates and Charges</u>

Basic Monthly Service Charge		$11.52
All Consumption –Charge Per Therm		
Margin (Non-Gas Costs)	PGA (Gas Costs)	Total Gas Costs
$0.55455	$0.93689	$1.49144

COST OF CAPITAL

Q. Is RUCO revising its adjustments to the Company proposed cost of capital?

A. No. RUCO is not revising the adjustment to the weighted cost of capital. This position is fully explained in the surrebuttal testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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SURREBUTTAL
TABLE OF CONTENTS TO RUCO SCHEDULES

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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	$ 1,089,082,745	$ 1,837,726,032	$ 1,463,404,389
2	Adjusted Operating Income (Loss)	$ 73,180,098	$ 73,180,098	$ 73,180,098	$ 76,939,110	$ 76,939,110	$ 76,939,110
3	Current Rate Of Return (Line 2 / Line 1)	6.68%	3.97%	4.98%	7.06%	4.19%	5.26%
4	Required Operating Income (Line 5 X Line 1)	$ 103,457,659	$ 103,457,659	$ 103,457,659	$ 96,205,213	$ 96,205,213	$ 96,205,213
5	Required Rate Of Return	9.45%	5.61%	7.04%	8.83%	5.24%	6.57%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 30,277,561	$ 30,277,561	$ 30,277,561	$ 19,266,103	$ 19,266,103	$ 19,266,103
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 2)	1.6586	1.6586	1.6586	1.6634	1.6634	1.6634
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 50,219,828	$ 50,219,828	$ 50,219,828	$ 32,046,846	$ 32,046,846	$ 32,046,846
9	Adjusted Test Year Revenue	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678	$ 399,234,678
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)	$ 449,454,506	$ 449,454,506	$ 449,454,506	$ 431,281,524	$ 431,281,524	$ 431,281,524
11	Required Percentage Increase In Revenue (Line 8 / Line 9)	12.58%	12.58%	12.58%	8.03%	8.03%	8.03%
12	Rate Of Return On Common Equity	11.25%	11.25%	11.25%	9.88%	9.88%	9.88%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Columns (D) Thru (F): Schedules SURR RLM-2, RLM-5, SURR RLM-6 And SURR RLM-18

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SURREBUTTAL
RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO OCRB ADJUSTMENTS	REF.	(C) RUCO ADJUSTED AS OCRB
1	Gas Plant In Service	$ 2,053,847,890	$ (677,012)	(1) & (4)	$ 2,053,491,657
	Less:				
2	Accumulated Depreciation And Amortization	752,275,563	(276,996)	(1)	751,998,567
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 1,301,572,327	$ (400,016)		$ 1,301,493,090
	Additions:				
4	Allowance For Working Capital (SURR RLM-6, Page 1)	$ 5,681,932	$ (5,628,064)	(2)	$ 53,868
5	Total Additions (Line 4)	$ 5,681,932	$ (5,628,064)		$ 53,868
	Deductions:				
6	Customer Advances In Aid Of Construction	$ (37,910,017)	$ -		$ (37,910,017)
7	Customer Deposits	(31,921,898)	-		(31,921,898)
8	Deferred Income Taxes	(142,632,297)	-	(3)	(142,632,297)
9	Total Deductions (Sum Of Lines 6, 7 & 8)	$ (212,464,212)	$ -		$ (212,464,212)
10	TOTAL ORIGINAL COST RATE BASE (Sum Of Lines 3, 5 & 9	$ 1,094,790,047	$ (6,028,081)		$ 1,089,082,745

References:
- Column (A): Company Schedule B-1
- Column (B): References:
  - (1) Schedule RLM-4, Page 1 (Adjustment is -$356,233)
  - (2) Schedule SURR RLM-6, Page 1
  - (3) Schedule RLM-3, Page 3
  - (4) See Surrebuttal Testimony - Adjustment No. 12 - Yuma Manors (Adjustment is -$320,779)
- Column (C): Column (A) + Column (B)

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SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5
SUMMARY OF THE ALLOWANCE FOR WORKING CAPITAL

LINE NO.	DESCRIPTION	REFERENCE		(A) AMOUNT
1	Cash Working Capital Per SWG	SWG SCH. B-5, Page 1	$	(10,379,937)
2	Cash Working Capital Per RUCO	SURR RLM-6, Page 2, Line 14		(16,349,492)
3	Adjustment	Line 2 - Line 1	$	(5,969,555)
4	Materials And Supplies Per SWG	SWG SCH. B-5, Page 1	$	12,389,898
5	Materials And Supplies Per RUCO	SWG SCH. B-5, Page 1		12,389,898
6	Adjustment	Line 5 - Line 4	$	-
7	Prepayments Per SWG	SWG SCH. B-5, Page 1	$	3,671,971
8	Prepayments Per RUCO	SURR RLM-6, Page 5, Line 15		4,013,462
9	Adjustment	Line 8 - Line 7	$	341,491
10	Total Adjustment	Sum Lines 3, 6, & 9	$	(5,628,064)

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SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
1	Cost Of Gas	$ 540,064,385	$ -	$ 540,064,385	42.30	$ 22,842,405,297
2	Labor Cost	117,038,570	(6,513,626)	110,524,944	12.33	1,363,305,727
3	Provision For Uncollectible Accts	2,977,729	-	2,977,729	120.00	357,327,523
4	Other O & M	54,826,860	11,033	54,837,893	17.72	971,476,853
	Total O & M Expenses	$ 714,907,544	$ (6,502,593)	$ 708,404,951	36.05	$ 25,534,515,400
5	Interest	$ 48,035,008	(250,413)	$ 47,784,595	79.50	$ 3,798,875,265
6	Taxes Other Than Income Taxes	33,124,880	-	33,124,880	185.34	6,139,365,177
7	Income Taxes	21,699,571	9,998,850	31,698,421	37.00	1,172,841,556
8	Revenue Taxes	97,747,450	3,278,392	101,025,842	57.51	5,809,996,195
9	Total Operating Expenses	$ 915,514,453	$ 3,245,844	$ 922,038,689	46.05	$ 42,455,593,594
10	Revenue Lag				39.53	Co. Workpapers
11					(6.52)	Line 10 - Line 9
12	Number Of Days In Test Period	365	Test Year			
13	Average Daily Operating Expenses	$ 2,508,259	Col. (A) Line 9 / Line 12			
14	Net Difference Rev - Exp Lag	(6.52)	Col. (D) Line 11			
15	Cash Working Capital	$ (16,349,492)	Col. (A), Line 13 X Line 14			

SURREBUTTAL

EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D

ALLOWANCE FOR WORKING CAPITAL - CALCULATION OF PREFERRED EQUITY LAG

LINE NO.	MID-POINT OF SERVICE PERIOD	(A) PAYMENT DATE	(B) PERCENT PAYMENT	(C) (LEAD)/LAG DAYS	(D) DOLLARS DAYS
1	7/1/2006	3/31/2006	25.00%	(92)	(23.00)
2	7/1/2006	6/30/2006	25.00%	(1)	(0.25)
3	7/1/2006	9/30/2006	25.00%	91	22.75
4	7/1/2006	12/31/2006	25.00%	183	45.75
5	Totals		100.00%		45.25
6	Preferred Equity Lag			45.25	

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SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - CALCULATION OF OTHER O & M LAG

LINE NO.	MONTH	(A) COST	(B) LAG DAYS	(C) DOLLAR DAYS
1	May 2006	$ 2,596,715	0.22	$ 566,253
2	June	2,611,117	35.16	91,799,499
3	July	2,546,481	18.55	47,227,421
4	August	2,460,510	36.74	90,404,740
5	September	2,021,521	35.60	71,973,470
6	October	3,018,228	52.99	159,935,937
7	November	2,733,777	45.29	123,820,351
8	December	3,394,550	(6.46)	(21,943,520)
9	January 2007	5,019,712	(2.82)	(14,168,034)
10	February	5,258,382	9.77	51,397,591
11	March	4,466,924	29.44	131,524,579
12	April	2,608,462	(17.75)	(46,306,652)
13	Total	$ 38,736,380	17.72	$ 686,231,635

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SURREBUTTAL
EXPLANATION OF TEST-YEAR RATE BASE ADJUSTMENT NO. 5 - CONT"D
ALLOWANCE FOR WORKING CAPITAL - CALCULATION OF ADJUSTED PREPAYMENTS

LINE NO.	MONTH	(A) BALANCE	(B) DEBITS	(C) CREDITS	(D) ADJUSTED BALANCE
1	April 2006	$ 5,367,019	$ -	$ -	$ 5,367,019
2	May	4,571,452	18,221	-	4,589,673
3	June	3,756,402	-	1,518	3,773,104
4	July	5,219,958	22,000	1,518	5,257,142
5	August	9,299,535	195,806	3,352	9,529,173
6	September	8,623,454	15,186	19,669	8,848,609
7	October	7,836,438	66,720	20,934	8,107,379
8	November	6,430,014	128,656	26,494	6,803,117
9	December	9,144,710	163,132	37,216	9,643,729
10	January 2007	8,343,687	112,506	50,810	8,904,402
11	February	7,723,320	126,085	60,186	8,349,935
12	March	6,044,664	76,149	70,693	6,676,735
13	April	5,600,962	13,396	77,038	6,169,390
14	Total	$ 87,961,615			$ 92,019,406
15	13 Month Average	$ 6,766,278		56.70%	$ 4,013,462

References:
Column (A): Company Schedule B-5, Page 4
Column (B): Company Schedule B-5, Workpaper Sheets 30 - 59
Column (C): Column (B) Prior Months Accurals / 12 Months
Column (D): Column (D) Prior Month + Column (B) Current Month - Column (C) Current Month + Column (A) Current Month - Column (A) Prior Month

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SURREBUTTAL
OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
1	Revenues	$ 399,234,678	$ -	$ 399,234,678	$ 32,046,846	$ 431,281,524
2	Gas Cost	-	-	-	-	-
3	TOTAL MARGIN	$ 399,234,678	$ -	$ 399,234,678	$ 32,046,846	$ 431,281,524
	EXPENSES:					
4	Other Gas Supply	$ 701,601	$ (25,254)	$ 676,347	$ -	$ 676,347
5	Distribution	89,528,455	(2,448,330)	87,080,125	-	87,080,125
6	Customer Accounts	38,730,909	(1,058,858)	37,672,051	-	37,672,051
7	Customer Information	1,126,796	(20,117)	1,106,679	-	1,106,679
8	Sales	-	-	-	-	-
	Administrative & General					
9	Direct	4,009,539	(290,519)	3,719,020	-	3,719,020
10	System Allocable	52,937,155	(2,659,515)	50,277,640	-	50,277,640
	Depreciation & Amortization					
11	Direct	80,956,247	(26,796)	80,929,450	-	80,929,450
12	System Allocable	6,646,938	(46,583)	6,600,356	-	6,600,356
13	Regulatory Amortizations	284,528	-	284,528	-	284,528
14	Other Taxes	33,124,880	(8,499)	33,116,381	-	33,116,381
15	Interest On Cust. Deposits	1,915,314	-	1,915,314	-	1,915,314
16	Income Taxes	16,092,218	2,825,460	18,917,678	12,780,743	31,698,421
17	TOTAL EXPENSES	$ 326,054,578	$ (3,759,011)	$ 322,295,568	$ 12,780,743	$ 335,076,311
		$ (2)				
18	NET INCOME (LOSS)	$ 73,180,098		$ 76,939,110		$ 96,205,213

References:
- Column (A): Company Schedule C-1
- Column (B): Testimony, RLM And Schedule SURR RLM-8
- Column (C): Column (A) + Column (B)
- Column (D): Testimony, RLM And Schedule SURR RLM-1, RLM-1, Page 2
- Column (E): Column (C) + Column (D)

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 LABOR AND LABOR LOAD SCH. RLM-9	(C) ADJ. NO. 2 INJURIES AND DAMAGES TSTM'Y-RLM	(D) ADJ. NO. 3 PAIUTE ANNUALZ'N TSTM'Y-RLM	(E) ADJ. NO. 4 ANNUALIZED DEP/AMORT SCH. RLM-10	(F) ADJ. NO. 5 ANNUALIZED PROP'TY TAX SCH. RLM-11	(G) ADJ. NO. 6 UNNECESS EXPENSES SURR-TSTM'Y	(H) ADJ. NO. 7 MIP SCH. RLM-13	(I) ADJ. NO. 8 SERP SCH. RLM-14
1	Revenues	$ 399,234,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ 399,234,678	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EXPENSES:									
4	Other Gas Supply	$ 701,601	$ (15,070)	$ -	$ -	$ -	$ -	$ -	$ -	$ (10,184)
5	Distribution	89,528,455	(1,364,268)	-	-	-	-	(91,649)	-	(949,044)
6	Customer Accounts	38,730,909	(619,707)	-	-	-	-	-	-	(428,347)
7	Customer Information	1,126,796	(11,910)	-	-	-	-	-	-	(8,206)
8	Sales	-	-	-	-	-	-	-	-	-
	Administrative & General		-	-	-	-	-	-	-	-
9	Direct	4,009,539	(21,716)	-	-	-	-	-	(145,002)	(54,102)
10	System Allocable	52,937,155	(580,819)	283,644	(17,702)	-	-	(93,561)	(1,760,046)	(491,031)
	Depreciation & Amortization		-	-	-	-	-	-	-	-
11	Direct	80,956,247	-	-	-	(11,621)	-	-	-	-
12	System Allocable	6,646,938	-	-	-	(46,583)	-	-	-	-
13	Regulatory Amortizations	284,528	-	-	-	-	-	-	-	-
14	Other Taxes	33,124,880	-	-	-	-	-	-	-	-
15	Interest On Cust. Deposits	1,915,314	-	-	-	-	-	-	-	-
16	Income Taxes	16,092,218	-	-	-	-	-	-	-	-
17	TOTAL EXPENSES	$ 326,054,579	$ (2,613,490)	$ 283,644	$ (17,702)	$ (58,204)	$ -	$ (185,210)	$ (1,905,048)	$ (1,940,914)
18	NET INCOME (LOSS)	$ 73,180,099								

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(J) ADJ. NO. 9 EMPLOYEE RECOGNITION TSTM'Y-RLM	(K) ADJ. NO. 10 UNCOLL'TIBLE EXPENSE SURR-TSTM'Y	(L) ADJ. NO. 11 GAIN ON SALE - PROPERTY SCH. RLM-16	(M) ADJ. NO. 12 YUMA MANORS SURR-TSTM'Y	(N) INTENT'LY LEFT BLANK	(O) INTENT'LY LEFT BLANK	(P) INTENT'LY LEFT BLANK	(Q) ADJ. NO. 13 INCOME TAX SURR RLM-17	(R) RUCO AS ADJUSTED
1	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 399,234,678
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 399,234,678
	EXPENSES:									
4	Other Gas Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 676,347
5	Distribution	(43,370)	-	-	-	-	-	-	-	87,080,125
6	Customer Accounts	(10,804)	-	-	-	-	-	-	-	37,672,051
7	Customer Information	-	-	-	-	-	-	-	-	1,106,679
8	Sales	-	-	-	-	-	-	-	-	-
									-	-
	Administrative & General	-	-	-	-	-	-	-	-	-
9	Direct	-	-	(69,699)	-	-	-	-	-	3,719,020
10	System Allocable	-	-	-	-	-	-	-	-	50,277,640
					-	-	-	-	-	-
	Depreciation & Amortization	-	-	-	-	-	-	-	-	-
11	Direct	-	-	-	(15,175)	-	-	-	-	80,929,450
12	System Allocable	-	-	-	-	-	-	-	-	6,600,356
13	Regulatory Amortizations	-	-	-	-	-	-	-	-	284,528
					-	-	-	-	-	-
14	Other Taxes	-	-	-	(8,499)	-	-	-	-	33,116,381
15	Interest On Cust. Deposits	-	-	-	-	-	-	-	-	1,915,314
16	Income Taxes	-	-	-	-	-	-	-	2,825,460	18,917,678
17	TOTAL EXPENSES	$ (54,174)	$ -	$ (69,699)	$ (23,674)	$ -	$ -	$ -	$ 2,825,460	$ 322,295,568
18	NET INCOME (LOSS)									$ 76,939,110

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE		(B) AMOUNT
	FEDERAL INCOME TAXES:			
1	Operating Income Before Taxes	Schedule SURR RLM-7, Column (C), Line 18 + Line 16	$	95,856,788
	LESS:			
2	Arizona State Tax	Line 11		(3,349,670)
3	Interest Expense	Note (A) Line 21		(47,784,595)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$	44,722,523
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 10		35.17%
6	Federal Income Tax Expense	Line 4 X line 5	$	15,731,106
	STATE INCOME TAXES:			
7	Operating Income Before Taxes	Line 1	$	95,856,788
	LESS:			
8	Interest Expense	Note (A) Line 21		(47,784,595)
9	State Taxable Income	Line 7 + Line 8	$	48,072,193
10	State Tax Rate	Tax Rate		6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$	3,349,670
	TOTAL INCOME TAX EXPENSE:			
12	Federal Income Tax Expense	Line 6	$	15,731,106
13	State Income Tax Expense	Line 11		3,349,670
14	South Georgia Amortization	Company Schedule C-1, Sheet 17, Column (C), Line 8 + Line 18		365,253
15	Investment Tax Credit	Company Schedule C-1, Sheet 17, Column (C), Line 19		(528,352)
16	Total Income Tax Expense Per RUCO	Sum Of Lines 12, 13, 14 & 15	$	18,917,678
17	Total Income Tax Expense Per Company Filing (Schedule C-1)			16,092,218
18	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See SURR RLM 7, Page 2, Column (Q))	Line 16 - Line 17	$	2,825,460

NOTE (A):
Interest Synchronization:

LINE NO.	DESCRIPTION		AMOUNT
19	Adjusted Rate Base (Schedule SURR RLM-2, Column (C), Line 10)	$	1,089,082,745
20	Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2)		4.39%
21	Interest Expense (Line 19 X Line 20)	$	47,784,595

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SURREBUTTAL
COST OF CAPITAL

		(A)	(B)	(C)
LINE NO.	DESCRIPTION	CAPITAL RATIO	COST	WEIGHTED COST
1	Long-term Debt	51.00%	7.96%	4.06%
2	Preferred Stock	4.00%	8.20%	0.33%
3	Common Equity	45.00%	9.88%	4.45%
4	TOTAL CAPITAL	100.00%		
5	WEIGHTED COST OF CAPITAL			8.83%

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) X Column (B)
Column (C) Line 5: Sum Of Column (C) Lines 1 Thru 3

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Schedule SURR RLM-19
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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		PROPOSED	ADJUSTED BILLING DETERMINANTS		PROPOSED MARGIN RATES		MARGIN AT PROPOSED RATES				
LINE NO.	DESCRIPTION	SCHEDULE NO.	NUMBER OF BILLS	SALES (THERMS)	BASIC SERVICE CHARGE	COMMODITY CHARGE	BASIC SERVICE CHARGE	COMMODITY CHARGE	TOTAL MARGIN	GAS COST	TOTAL REVENUE
	Single-Family Residential Gas Service	G-5									
	Summer (May - October)										
1	Basic Service Charge per Month		5,107,859		$ 11.52		$ 58,847,277		$ 58,847,277		$ 58,847,277
	Commodity Charge per Therm										
2	First 15 Therms			48,048,640		$ 0.55455		$ 26,645,248	26,645,248	$ 45,016,291	71,661,539
3	Over 15 Therms			16,007,105		0.55455		8,876,698	8,876,698	14,996,896	23,873,594
	Winter (November - April)										
4	Basic Service Charge per Month		5,190,171		$ 11.52		$ 59,795,587		$ 59,795,587		$ 59,795,587
	Commodity Charge per Therm										
5	First 35 Therms			133,956,357		$ 0.55455		74,285,147	74,285,147	125,502,371	199,787,518
6	Over 35 Therms			91,044,013		0.55455		50,488,219	50,488,219	85,298,225	135,786,444
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 118,642,864	$ 160,295,312	$ 278,938,176	$ 270,813,783	$ 549,751,959
8	Ratio Of Fixed To Variable Revenues						42.53%	57.47%	64.68%		
	Low Income Single-Family Residential Gas Svc	G-10									
	Summer (May - October)										
9	Basic Service Charge		153,923		$ 7.26		$ 1,118,019		$ 1,118,019		$ 1,118,019
	Commodity Charge per Therm										
	Summer (May - October)										
10	First 15 Therms			1,499,731		$ 0.55455		$ 831,672	831,672	$ 1,226,000	2,057,672
11	Over 15 Therms			343,792		0.55455		190,649	190,649	281,043	471,692
	Winter (November - April)										
12	Basic Service Charge per Month		156,983		$ 7.26		$ 1,140,245		$ 1,140,245		$ 1,140,245
	Commodity Charge per Therm										
13	First 35 Therms			4,229,842		$ 0.55455		2,345,648	2,345,648	3,457,811	5,803,459
14	Next 115 Therms			2,532,839		0.55455		1,404,579	1,404,579	2,070,545	3,475,124
15	Over 150 Therms			52,769		0.55455		29,263	29,263	43,137	72,400
16	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,258,264	$ 4,801,811	$ 7,060,075	$ 7,078,536	$ 14,138,611
17	Ratio Of Fixed To Variable Revenues						31.99%	68.01%	1.64%		
	Special Residential Gas Service for Air Conditioning	G-15									
	Summer (May - October)										
18	Basic Service Charge per Month		648		$ 11.52		$ 7,466		$ 7,466		$ 7,466
	Commodity Charge per Therm										
19	First 15 Therms			7,899		$ 0.55455		$ 4,380	4,380	$ 7,326	11,706
20	Over 15 Therms			65,327		0.55455		36,227	36,227	60,589	96,816
	Winter (November - April)										
21	Basic Service Charge per Month		648		$ 11.52		$ 7,466		$ 7,466		$ 7,466
	Commodity Charge per Therm										
22	First 35 Therms			19,309		$ 0.55455		10,708	10,708	17,909	28,617
23	Over 35 Therms			48,985		0.55455		27,165	27,165	45,433	72,598
24	Total Special Residential Gas Service		1,296	141,520			$ 14,932	$ 78,480	$ 93,412	$ 131,257	$ 224,669
25	Ratio Of Fixed To Variable Revenues						15.99%	84.01%	0.02%		

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) GAS COST	(J) TOTAL REVENUE
	Multi-Family Residential Gas Service	G-6									
	Summer (May - October)										
26	Basic Service Charge per Month		182,409		$ 9.02		$ 1,644,737		$ 1,644,737		$ 1,644,737
	Commodity Charge per Therm										
27	First 7 Therms			1,044,432		$ 0.55455		$ 579,187	579,187	$ 978,518	1,557,705
28	Over 7 Therms			950,005		0.55455		526,823	526,823	890,050	1,416,873
	Winter (November - April)										
29	Basic Service Charge per Month		188,153		$ 9.02		$ 1,696,529		$ 1,696,529		$ 1,696,529
	Commodity Charge per Therm										
30	First 18 Therms			2,633,090		$ 0.55455		1,460,173	1,460,173	2,466,916	3,927,089
31	Over 18 Therms			1,880,532		0.55455		1,042,844	1,042,844	1,761,851	2,804,695
32	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,341,266	$ 3,609,027	$ 6,950,293	$ 6,097,335	$ 13,047,628
33	Ratio Of Fixed To Variable Revenues						48.07%	51.93%	1.61%		
	Low Income Multi-Family Residential Gas Svc	G-11									
	Summer (May - October)										
34	Basic Service Charge per Month		13,560		$ 7.26		$ 98,493		$ 98,493		$ 98,493
	Commodity Charge per Therm										
35	First 7 Therms			79,822		$ 0.55455		$ 44,265	44,265	$ 65,253	109,518
36	Over 7 Therms			78,071		0.55455		43,294	43,294	63,822	107,116
	Winter (November - April)										
37	Basic Service Charge per Month		13,828		$ 7.26		$ 100,440		$ 100,440		$ 100,440
	Commodity Charge per Therm										
38	First 18 Therms			207,982		$ 0.55455		115,336	115,336	170,021	285,357
39	Next 132 Therms			186,423		0.55455		103,380	103,380	152,397	255,777
40	Over 150 Therms			345		0.55455		191	191	282	473
41	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 198,933	$ 306,466	$ 505,399	$ 451,775	$ 957,174
42	Ratio Of Fixed To Variable Revenues						39.36%	60.64%	0.12%		
		0.554547384									
43	Total Residential Gas Service		11,008,182	304,917,309			124,456,259	169,091,096	293,547,355	284,572,686	578,120,041
	Ratio Of Fixed To Variable Revenues						42.40%	57.60%	68.06%		
	Master Metered Mobile Home Park Gas Service	G-20									
44	Basic Service Charge per Month		1,968		$ 60.11		$ 118,300		$ 118,300		$ 118,300
	Commodity Charge per Therm All Usage										
45	All Usage			2,223,993		$ 0.39550		$ 879,584	879,584	$ 2,083,637	2,963,221
46	Total MMMHP Gas Service		1,968	2,223,993			$ 118,300	$ 879,584	$ 997,884	$ 2,083,637	$ 3,081,521
							11.86%	88.14%	0.23%		
	General Gas Service - Small	G-25(S)									
47	Basic Service Charge Per Month		201,805		$ 25.05		$ 5,054,515		$ 5,054,515		$ 5,054,515
	Commodity Charge per Therm All Usage										
48	Transportation Customers			10,138		$ 0.68244	-	$ 6,919	6,919	$ 8,288	15,207
49	Sales Customers			5,010,616		$ 0.68244		3,419,421	3,419,421	4,647,246	8,066,667
50	Total Small General Gas Service		201,805	5,020,754			$ 5,054,515	$ 3,426,340	$ 8,480,855	$ 4,655,534	$ 13,136,389
51	Ratio Of Fixed To Variable Revenues						59.60%	40.40%	1.97%		

SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) GAS COST	(J) TOTAL REVENUE
	General Gas Service - Medium	G-25(M)									
52	Basic Service Charge		193,790		$ 41.67		$ 8,075,079		$ 8,075,079		$ 8,075,079
	Commodity Charge per Therm All Usage										
53	Transportation Customers			172,365		$ 0.39263		$ 67,676	67,676	$ 140,905.00	208,581
54	Sales Customers			45,357,904		$ 0.39263		17,808,850	17,808,850	42,068,549	59,877,399
55	Total Medium General Gas Service		193,790	45,530,269			$ 8,075,079	$ 17,876,526	$ 25,951,605	$ 42,209,454	$ 68,161,059
56	Ratio Of Fixed To Variable Revenues						31.12%	68.88%	6.02%		
	General Gas Service - Large	G-25(L)									
57	Basic Service Charge		85,510		$ 153.27		$ 13,105,786		$ 13,105,786		$ 13,105,786
	Commodity Charge per Therm All Usage										
58	Transportation Customers			3,556,829		$ 0.27629		$ 982,720	982,720	$ 2,907,637.00	3,890,357
59	Sales Customers			145,666,025		$ 0.27629		40,246,200	40,246,200	135,102,325	175,348,525
60	Total Large General Gas Service		85,510	149,222,854			$ 13,105,786	$ 41,228,920	$ 54,334,706	$ 138,009,962	$ 192,344,668
61	Ratio Of Fixed To Variable Revenues						24.12%	75.88%	12.60%		
	General Gas Service - Transportation Eligible	G-25(TE)									
62	Basic Service Charge		2,222		$ 910.02		$ 2,022,059		$ 2,022,059		$ 2,022,059
63	Demand Charge per Month			12,803,712	0.061331			$ 9,423,139	9,423,139		9,423,139
	Commodity Charge per Therm All Usage										
64	Transportation Customers			32,517,415		$ 0.09485		$ 3,084,360	3,084,360	$ 26,582,336	29,666,696
65	Sales Customers			67,008,985		$ 0.09485		6,355,974	6,355,974	62,149,493	68,505,467
66	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,022,059	$ 18,863,473	$ 20,885,532	$ 88,731,829	$ 109,617,361
67	Ratio Of Fixed To Variable Revenues						9.68%	90.32%	4.84%		
68	Total General Gas Service		483,327	299,300,277			28,257,439	81,395,259	109,652,698	273,606,779	383,259,477
69	Ratio Of Fixed To Variable Revenues						25.77%	74.23%	25.42%		
	Air Conditioning Gas Service	G-40									
	Basic Service Charge										
70	With Other Service - No BSC		60		$ 0.00		$ -		$ -		$ -
71	General Service - Small		198		25.05		4,959		4,959		4,959
72	General Service - Medium		0		41.67		-		-		-
73	General Service - Large		48		153.27		7,357		7,357		7,357
74	Essential Agricultural		12		910.02		10,920		10,920		10,920
	Commodity Charge per Therm All Usage										
75	Transportation Customers			373,987		$ 0.09093		$ 34,007	34,007	$ 305,727	339,734
76	Sales Customers			744,265		$ 0.09093		67,677	67,677	690,291	757,968
77	Total Air Conditioning Gas Service		318	1,118,252			23,236	101,684	124,920	996,018	1,120,938
78	Ratio Of Fixed To Variable Revenues						18.60%	81.40%	0.03%		
	Street Lighting Gas Service	G-45									
	Commodity Charge per Therm of Rated Capacity										
79	All Usage		324	102,289		$ 0.66957		$ 68,490	$ 68,490	$ 94,871	$ 163,361
80	Total Street Lighting Gas Service		324	102,289			$ -	$ 68,490	$ 68,490	$ 94,871	$ 163,361
81	Ratio Of Fixed To Variable Revenues						0.00%	100.00%	0.02%		

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	DESCRIPTION	(A) PROPOSED SCHEDULE NO.	(B) ADJUSTED BILLING DETERMINANTS NUMBER OF BILLS	(C) SALES (THERMS)	(D) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(E) COMMODITY CHARGE	(F) MARGIN AT PROPOSED RATES BASIC SERVICE CHARGE	(G) COMMODITY CHARGE	(H) TOTAL MARGIN	(I) GAS COST	(J) TOTAL REVENUE
	Gas Service for Compression on Customer's Premises	G-55									
	Basic Service Charge										
82	Small		252		$ 25.05		$ 6,312		$ 6,312		$ 6,312
83	Large		288		239.48		68,970		68,970		68,970
84	Residential		1,272		11.52		14,655		14,655		14,655
	Commodity Charge per Therm All Usage										
85	Transportation Customers			0		$ 0.16824		$ -	$ -	$ -	$ -
	Sales Customers										
86	Small			177,495		$ 0.16824		29,862	29,862	164,623	194,485
87	Large			2,060,152		$ 0.16824		346,604	346,604	1,910,750	2,257,354
88	Residential			77,361		$ 0.16824		13,015	13,015	71,751	84,766
89	Total CNG Gas Service		1,812	2,315,008			89,937	389,481	479,418	2,147,124	2,626,542
90	Ratio Of Fixed To Variable Revenues						18.76%	81.24%	0.11%		
	Electric Generation Gas Service	G-60									
	Basic Service Charge										
91	General Service - Small		36		$ 25.05		$ 902		$ 902		$ 902
92	General Service - Medium		36		41.67		1,500		1,500		1,500
93	General Service - Large		84		153.27		12,874		12,874		12,874
94	General Service - Transportation Eligible		84		-		0		0		0
95	Essential Agricultural		12		114.95		1,379		1,379		1,379
	Commodity Charge per Therm All Usage										
96	Transportation Customers			0		$ 0.11842		$ -	$ -	$ -	$ -
97	Sales Customers			21,521,946		$ 0.11842		2,548,736	2,548,736	19,961,174	22,509,910
98	Total Electric Generation Gas Service		252	21,521,946			16,655	2,548,736	2,565,391	19,961,174	22,526,565
99	Ratio Of Fixed To Variable Revenues						0.65%	99.35%	0.59%		
	Essential Agriculture User Gas Service	G-75									
100	Basic Service Charge		1,216		$ 114.95		$ 139,779		$ 139,779		$ 139,779
	Commodity Charge per Therm All Usage										
101	Transportation Customers			6,217,976		$ 0.22353		$ 1,389,898	1,389,898	$ 5,083,071.00	6,472,969
102	Sales Customers			7,214,684		$ 0.22353		1,612,692	1,612,692	6,691,475	8,304,167
103	Total Essential Agricultural Gas Service		1,216	13,432,660			139,779	3,002,590	3,142,369	11,774,546	14,916,915
104	Ratio Of Fixed To Variable Revenues						4.45%	95.55%	0.73%		
	Natural Gas Engine Gas Service	G-80									
	Basic Service Charge										
105	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ -		$ -		$ -
106	Peak Season (April - September)		2,589		119.74		310,005		310,005		310,005
	Commodity Charge per Therm All Usage										
107	Transportation Customers			0		$ 0.17957		$ -	$ -	$ -	$ -
108	Sales Customers			13,070,981		$ 0.17957		2,347,162	2,347,162	9,591,355	11,938,517
109	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 310,005	$ 2,347,162	$ 2,657,167	$ 9,591,355	$ 12,248,522
110	Ratio Of Fixed To Variable Revenues						11.67%	88.33%	0.62%		
111	Total Tariff Sales		11,502,504	658,002,715			$ 153,411,610	$ 259,824,082	$ 413,235,692	$ 604,828,190	$ 1,018,063,882
112	Optional Gas Service	G-30	84	49,447,344			120,540	3,135,458	3,255,998	40,422,215	43,678,213
113	Special Contract Service	B-1	244	35,660,859			449,274	2,078,755	2,528,029		2,528,029
114	Other Operating Revenues						12,261,805		12,261,805		12,261,805
115	Total		11,502,832	743,110,918			$ 166,243,229	$ 265,038,296	$ 431,281,525	$ 645,250,405	$ 1,076,531,930
116	Ratio Of Fixed To Variable Revenues						38.55%	61.45%	100.00%		
117	Total Revenue Requirement								431,281,524	645,249,274	1,076,530,798
118	Over/(Under)								$ 1	$ 1,131	$ 1,132

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SURREBUTTAL
SINGLE - FAMILY RESIDENTIAL TYPICAL BILL ANALYSIS
COMPARISON OF PRESENT MONTHLY CHARGES TO COMPANY PROPOSED AND RUCO PROPOSED

LINE NO.	DESCRIPTION	(A) USAGE THERMS		(B) TOTAL MONTHLY COST PRESENT RATES		(C) TOTAL MONTHLY COST COMPANY PROPOSED		(D) TOTAL MONTHLY COST RUCO PROPOSED		(E) RUCO INCREASE OVER PRESENT CHANGE	(F) RUCO INCREASE OVER PRESENT PERCENTAGE
	Single-Family Residential Gas Service										
	Summer (May - October)										
1	50% Average Summer Usage per Month	6	$	18.97	$	22.15	$	20.87	$	1.90	10.01%
2	75% Average Summer Usage per Month	9	$	23.61	$	26.82	$	25.55	$	1.94	8.21%
3	**100% Average Monthly Summer Use**	**13**	**$**	**28.25**	**$**	**31.49**	**$**	**30.22**	**$**	**1.98**	**7.00%**
4	125% Average Summer Usage per Month	16	$	32.86	$	36.17	$	34.90	$	2.05	6.23%
5	150% Average Summer Usage per Month	19	$	37.36	$	40.84	$	39.58	$	2.21	5.92%
	Winter (November - April)										
6	50%Average Winter Usage per Month	22	$	41.76	$	45.11	$	43.85	$	2.09	5.01%
7	75%Average Winter Usage per Month	33	$	57.78	$	61.27	$	60.01	$	2.23	3.86%
8	**100% Average Monthly Winter Use**	**43**	**$**	**73.47**	**$**	**77.42**	**$**	**76.18**	**$**	**2.71**	**3.68%**
9	125% Average Winter Usage per Month	54	$	89.05	$	93.58	$	92.34	$	3.29	3.69%
10	150% Average Winter Usage per Month	65	$	104.64	$	109.73	$	108.50	$	3.87	3.70%

RATE SCHEDULES

	DESCRIPTION		BASIC SERVICE CHARGE		NON-GAS COSTS		GAS COST		TOTAL GAS COST
	PRESENT RATES								
	Single-Family Residential Gas Service								
	Summer (May - October)								
11	Basic Service Charge per Month	$	9.70						
	Commodity Charge per Therm								
12	First 15 Therms			$	0.54200	$	0.93689	$	1.47889
13	Over 15 Therms			$	0.50100	$	0.93689	$	1.43789
	Winter (November - April)								
14	Basic Service Charge per Month	$	9.70						
	Commodity Charge per Therm								
15	First 35 Therms			$	0.54200	$	0.93689	$	1.47889
16	Over 35 Therms			$	0.50100	$	0.93689	$	1.43789
	COMPANY PROPOSED RATES								
	Single-Family Residential Gas Service								
	All Year Around And All Usage								
17	Basic Service Charge per Month	$	12.80						
18	Non- Weather Sensitive Use - Commodity Charge per Therm			$	0.88069	$	0.60996	$	1.49065
19	Weather Sensitive Use - Commodity Charge per Therm			$	-	$	1.49065	$	1.49065
	RUCO PROPOSED RATES								
	Single-Family Residential Gas Service								
	All Year Around And All Usage								
20	Basic Service Charge per Month	$	11.52						
21	Commodity Charge per Therm			$	0.554547	$	0.93689	$	1.49144